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October 31, 2006

VIA HAND DELIVERY

The Honorable Charles L.A. Terreni
Chief Clerk and Administrator
The Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE:
- Duke Energy Carolinas, LLC ("Duke Energy Carolinas") Annual Review of Base Rates for Fuel Costs.
- Docket Number 2006-3-E.
- **Filing of Materials Related to Catawba Outage.**

Dear Mr. Terreni:

On September 29, 2006, the Public Service Commission of South Carolina ("Commission") issued its Order No. 2006-554, Order Regarding Prudence Review of Fuel Purchasing Practices in the above-referenced Docket. In this Order the Commission approved a Settlement Agreement between the parties in this Docket dated August 14, 2006. Paragraph (5) of that Settlement Agreement required Duke Energy Carolinas to provide reports/materials related to the May 26, 2006, Catawba Outages, to the Commission and the South Carolina Office of Regulatory Staff ("ORS").

Copies of responsive reports/materials have now been provided to the ORS and Duke Energy Carolinas, through counsel, hereby files identical copies of these reports/materials with this Commission.

For the record, these reports/materials consist of (i) June 29, 2006, correspondence from the United States Nuclear Regulatory Commission ("NRC") addressed to Duke Energy Corporation transmitting the NRC's Augmented Inspection Team Report, (ii) July 28, 2006, correspondence from the NRC addressed to Duke Energy Corporation transmitting the NRC's Integrated Inspection Report and (iii) the

Duke Energy Carolinas' Significant Event Investigation Team- Final Report of August 4, 2006.

This correspondence is being copied to all parties of record in this Docket. However, because of the voluminous nature of these reports/materials, we are not providing copies to other parties of record. We request that any party of record needing these materials to contact the undersigned so that we may arrange for the delivery of the same.

If you have any questions or concerns please do not hesitate to contact the undersigned.

With kind regards, we are

Sincerely,

Richard L. Whitt

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

July 28, 2006

Duke Energy Corporation
ATTN: Mr. D. M. Jamil
Site Vice President
Catawba Nuclear Station
4800 Concord Road
York, SC 29745

SUBJECT: CATAWBA NUCLEAR STATION - NRC INTEGRATED INSPECTION REPORT 05000413/2006003 AND 05000414/2006003

Dear Mr. Jamil:

On June 30, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Catawba Nuclear Station Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on July 12, 2006, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents an NRC-identified finding of very low safety significance (Green) which was determined to involve a violation of NRC requirements. Additionally, a licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. However, because of the very low safety significance and because they have been entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCV) in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you contest any NCV in this report, you should provide a written response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC, 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC, 20555-0001; and the NRC Resident Inspector at the Catawba Nuclear Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at *www.nrc.gov/reading-rm/adams.html* (the Public Electronic Reading Room).

ML062090108

Sincerely,

/RA/

Michael E. Ernstes, Chief
Reactor Projects Branch 1
Division of Reactor Projects

Docket Nos.: 50-413, 50-414
License Nos.: NPF-35, NPF-52

Enclosure: Integrated Inspection Report 05000413/2006003
and 05000414/2006003
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-413, 50-414
License Nos.:	NPF-35, NPF-52
Report No.:	05000413/2006003 and 05000414/2006003
Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 and 2
Location:	York, SC 29745
Dates:	April 1, 2006 through June 30, 2006
Inspectors:	E. Guthrie, Senior Resident Inspector A. Sabisch, Resident Inspector G. Williams, Project Engineer R. Moore, Senior Reactor Inspector (Sections 1R02 and 1R17) M. Scott, Reactor Inspector (Sections 1R02 and 1R17) C. Smith, Senior Reactor Inspector (Sections 1R02 and 1R17) J. Rivera-Ortiz, Reactor Inspector (Section 1R08) J. Fuller, Reactor Inspector (Section 1R08)
Approved by:	Michael E. Ernstes, Chief Reactor Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000413/2006-003, 05000414/2006-003; 4/1/2006 - 6/30/2006; Catawba Nuclear Station, Units 1 and 2; Event Followup.

The report covered a three-month period of inspection by two resident inspectors, a project engineer, a senior reactor inspector, and four reactor inspectors. One Green finding which was a non-cited violation (NCV) was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," (ROP) Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified an NCV of Technical Specifications 5.4.1.b, for failure to adequately establish and implement procedures required by Regulatory Guide 1.33, Appendix A, Section 9, Procedures for Performing Maintenance. Specifically, no procedure or program existed to periodically inspect underground electrical conduit seals to identify and repair any degradation of seals which provided protection from external flooding.

  The finding was more than minor in that it is associated with the protection against External Factors attribute and affected the Mitigating Events cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The performance deficiency associated with this finding was that the licensee failed to establish a program, process or procedure to periodically inspect and assess the condition of seals in below-grade electrical conduits to identify degradation and ensure that the seals were properly maintained or repaired as needed. (Section 4OA5.1)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violation and corrective action document numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period operating at 100 percent (%) Rated Thermal Power (RTP). On May 20, a fault in the switchyard resulted in a loss of offsite power and a reactor trip. The unit was forced to cool down to Mode 5 to clean biological debris from several cooling system components located inside of containment. The unit was returned to 100% RTP on June 12 and remained there through the end of the inspection period.

Unit 2 began the inspection period in a refueling outage. The unit reached 100% RTP on April 30. On May 20, a fault in the switchyard resulted in a loss of offsite power and a reactor trip. The unit was stabilized in Mode 3. The unit was returned to 100% RTP on May 29 and remained there through the end of the inspection period.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

.1 Seasonal Weather Preparation

a. Inspection Scope

The inspectors reviewed the licensee's preparations for adverse weather associated with high ambient temperatures. This included field walkdowns to assess the material condition and operation of ventilation and cooling equipment as well as other preparations made to protect plant equipment from high ambient temperature conditions. Risk significant systems reviewed included portions of the standby shutdown facility and the nuclear service water pump house structure. In addition, the inspectors conducted discussions with operations, engineering, and maintenance personnel responsible for implementing the hot weather preparation program to assess the licensee's ability to identify and resolve deficient conditions associated with hot weather protection equipment prior to actual hot weather being experienced at the site. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R02 Evaluations of Changes, Tests or Experiments

a. Inspection Scope

The inspectors reviewed selected samples of evaluations to confirm that the licensee had appropriately considered the conditions under which changes to the facility, Updated Final Safety Analysis Report (UFSAR), or procedures may be made, and tests conducted, without prior NRC approval. The inspectors reviewed eight evaluations for changes and additional information, such as calculations, supporting analyses, the

UFSAR, and drawings to confirm that the licensee had appropriately concluded that the changes could be accomplished without obtaining a license amendment. The evaluations reviewed are listed in the Attachment.

The inspectors also reviewed samples of changes for which the licensee had determined that evaluations were not required, to confirm that the licensee's conclusions to "screen out" these changes were correct and consistent with 10 CFR 50.59. The 16 "screened out" changes reviewed are listed in the Attachment.

The inspectors also reviewed problem investigation reports (PIPs) and 10 CFR 50.59 committee meeting notes to verify that problems were identified at an appropriate threshold, were entered into the corrective action process, and appropriate corrective actions had been initiated.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdowns

a. Inspection Scope

The inspectors walked down the following five system alignments to verify that critical portions of equipment alignments remained operable while the redundant trains for that system were inoperable. The inspectors reviewed plant documents to determine the correct system and power alignments, as well as the required positions of selected valves and breakers. The inspectors reviewed equipment alignment problems which could cause initiating events or impact mitigating system availability to verify that they had been properly identified and resolved. Documents reviewed are listed in the Attachment.

- 2B diesel generator and 2B 4160-volt switchgear while the 2A diesel generator was removed from service for planned maintenance
- 2A diesel generator, 2B diesel generator, 4160-volt switchgear and turbine building switchgear when Unit 2 entered reduced inventory/mid-loop conditions following core reload in preparation for vacuum refill of the reactor coolant system
- Emergency core cooling system equipment and diesel generators on both units while external inspections of the nuclear service water (RN) headers were being performed
- Protection of B train equipment following the identification of a through-wall leak on the 2A component cooling water heat exchanger RN discharge piping
- 1B diesel generator and 1B 4160-volt vital switchgear when then 1A diesel generator was inoperable due to room flooding

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors conducted a detailed walkdown of the Unit 2 safety injection (NI) system. The inspectors utilized licensee procedures, as well as licensing and design documents to verify that the system (i.e., pump, valve, and electrical) alignment was correct. During the walkdowns, the inspectors also verified that: valves and pumps did not exhibit leakage that would impact their function; major portions of the system and components were correctly labeled; hangers and supports were correctly installed and functional; and essential support systems were operational. In addition, pending design and equipment issues were reviewed to determine if the identified deficiencies significantly impacted the system's functions. Items included in this review were: the operator workaround list, the temporary modification list, system Health Reports, and outstanding maintenance work requests/work orders. A review of open PIPs was also performed to verify that the licensee had appropriately characterized and prioritized NI-related equipment problems for resolution in the corrective action program. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection - Walkdowns

a. Inspection Scope

The inspectors walked down accessible portions of the following eight plant areas to assess the licensee's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. The inspectors observed the fire protection suppression and detection equipment to determine whether any conditions or deficiencies existed which could impair the operability of that equipment. The inspectors selected the areas based on a review of the licensee's safe shutdown analysis probabilistic risk assessment, sensitivity studies for fire-related core damage accident sequences, and summary statements related to the licensee's 1992 Initial Plant Examination for External Events submittal to the NRC. Documents reviewed are listed in the Attachment.

- Unit 2 annulus area (conducted during the Unit 2 refueling outage)
- Unit 2 exterior doghouse
- Unit 1, A and B residual heat removal (ND) pump rooms
- Unit 2, A and B containment spray (NS) pump rooms
- Unit 1, A and B charging (NV) pump rooms

- Unit 1, A diesel generator room and associated corridor
- Unit 2 mechanical penetration room, 560 foot elevation
- Unit 1, A and B auxiliary shutdown panel rooms

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance - Annual Resident Inspection

a. Inspection Scope

The inspectors observed the performance of (Periodic Test) PT/2/A/4400/006B, Containment Spray Heat Exchanger 2B Heat Capacity Test, and evaluated the test data for acceptable performance. The inspectors also conducted discussions with test personnel concerning system configuration and heat load requirements, the methodology used in calculating heat exchanger performance, and the method for tracking the status of tube plugging activities via the data logger and computer processing equipment. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (3 Samples)

a. Inspection Scope

Piping Systems and Containment ISI. The inspectors reviewed the implementation of the licensee's ISI program for monitoring degradation of the reactor coolant system (RCS) boundary and the risk significant piping system boundaries. The inspectors selected a sample of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI-required examinations for review. The inspectors reviewed nondestructive examination (NDE) activities to evaluate compliance with Technical Specifications (TSs) and the applicable editions of ASME Section V and XI (1989 Edition/No Addenda for examinations credited to the second 10-year ISI interval, and 1998 Edition/2000 Addenda for examinations credited to the third 10-year ISI interval), and to verify that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the requirements of ASME Section XI, IWB-3000 or IWC-3000 acceptance standards. Specifically, the inspectors directly observed the NDE activities described below and reviewed their corresponding NDE procedures, NDE reports, equipment and consumables certification records, and personnel qualifications records. Documents reviewed are listed in the Attachment.

- Ultrasonic (UT) examination of welds 2NI89-6, 2NI89-7, 2NI89-10, and 2NI89-11 (6-inch pipe in Safety Injection System, ASME Class 2)
- Liquid Penetrant (PT) examination of welds 2NC-89-4, 2NC-89-12, 2NC-89-13,

2NC-89-20, and 2NC-89-21 (2-inch line in Reactor Coolant System, ASME Class 1)

The inspectors reviewed final NDE reports for the welds referenced below to verify that the evaluation and disposition of indications was in accordance with the applicable version of ASME Section XI, IWB-3000.

- UT examination of Reactor Pressure Vessel welds 2RPV-101-124B, 2RPV-101-142A, 2RPV-101-142C, and 2RPV-101-171 (ASME Class 1)
- Radiographic (RT) examination of RCS welds 2NC-9-03 and 2SGA-Outlet-SE (RCS Cold Leg to Steam Generator (SG) weld, safe end to pipe weld, ASME Class 1)

The inspectors reviewed welding procedures, procedure qualification records, welder qualification records, and NDE reports (RT film, as applicable) listed in the Attachment for the following three welds.

- Weld 2BB61-23-1, 2-inch diameter socket weld, SG Blowdown System, ASME Class 2
- Weld 2492-NS.00-46-18-1, 8-inch diameter butt weld, Containment Spray System, ASME Class 2
- Weld 2CA62-12, 4-inch diameter butt weld, Auxiliary Feedwater System, ASME Class 2

In addition, the inspectors reviewed the implementation of the licensee's Containment ISI Program for monitoring the integrity of the containment structures. The inspectors reviewed a sample of wall thickness data for UT examinations performed in the containment liner surface area grids as part of the inspections scheduled for the second containment ISI interval. The inspectors compared the data to the acceptable standards of ASME Section XI, 1998 Edition/1999 and 2000 Addenda. The inspectors also conducted a containment walkdown of multiple elevations and peripheral locations to assess, in general, the material condition of structures, systems, and components.

Boric Acid Corrosion Control (BACC) Program. The inspectors reviewed the licensee's BACC activities to ensure implementation with commitments made in response to NRC Generic Letter 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary, and applicable industry guidance documents. The inspectors reviewed procedures and the results of the licensee's Mode 3 containment walkdown inspection from this outage. The inspectors also conducted an independent walkdown of the reactor building to evaluate compliance with the licensee BACC program and to verify that degraded or non-conforming conditions, such as boric acid leaks identified during the Mode 3 containment walkdown, were properly identified and corrected in accordance with the licensee's corrective action program. The inspectors reviewed the following engineering evaluations completed for evidence of boric acid found on systems containing borated water to verify that the minimum design code-required section thickness had been maintained for the affected components.

- PIP C-05-06604, active boric acid leak in valve 2NV-232 (Chemical and Volume Control System)
- PIP C-05-05624, boric acid leak at a threaded piping joint at the mechanical seal

housing of ND Pump 2A (Residual Heat Removal System)

Steam Generator (SG) Tube Inservice Inspection. The inspectors reviewed the Unit 2 SG tube eddy current testing (ECT) examination activities to ensure compliance with TSs, applicable industry operating experience and technical guidance documents, and ASME Code Section XI requirements. The inspectors reviewed licensee SG inspection activities to ensure that ECT inspections conducted this outage conformed to the Duke Power Steam Generator Management Program Manual. The inspectors reviewed the SG examination scope, ECT acquisition procedures, Examination Technique Specification Sheets (ETSS), ECT analysis guidelines, the current SG specific assessment of potential degradation mechanisms, SG Operational Assessment and Condition Monitoring documents from the previous Unit 2 outage, and the SG tube plugging and stabilization procedures. The inspectors reviewed documentation to ensure that the ECT probes and equipment configurations used were qualified to detect the expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination," of EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6." In addition, the inspectors reviewed the qualification and certification records for the ECT standards, SG tube plugs, SG tube stabilizers, and ECT data analysis and resolution analysis personnel.

The secondary side water chemistry and loose parts monitoring programs were reviewed to ensure that they were consistent with applicable industry guidance documents. The inspectors independently reviewed the licensee's secondary side visual examination results and associated evaluations for loose parts that are not retrievable and will remain in the steam generators during the next operating cycle. The inspectors observed ECT acquisition, resolution analysis, tube stabilization, and tube plugging activities.

Identification and Resolution of Problems. The inspectors performed a review of ISI-related problems, including welding, BACC and SG ISI, that were identified by the licensee and entered into the corrective action program as PIP documents. The inspectors reviewed the PIPs to confirm that the licensee had appropriately described the scope of the problem and had initiated corrective actions. The inspectors performed this review to ensure compliance with 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requirements. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

Resident Quarterly Observation

a. Inspection Scope

The inspectors observed the Catawba Nuclear Station Annual Graded Exercise conducted on May 16 to assess the performance of licensed operators and to verify that evaluators were identifying and documenting crew performance weaknesses. The exercise included a leak in the reactor coolant system piping that increases in size during the exercise, fuel cladding failure caused by debris moving through the core, and a breach of the containment into the annulus, resulting in an off-site release. The inspection focused on high-risk operator actions performed during implementation of the emergency operating procedures, emergency plan implementation and classification, and the incorporation of lessons learned from previous plant events. The inspectors observed the critique following the exercise to verify that appropriate feedback was provided to the licensed operators regarding identified weaknesses. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's effectiveness in performing the following routine maintenance activity. This review included an assessment of the licensee's practices pertaining to the identification, scope, and handling of degraded equipment conditions, as well as common cause failure evaluations and the resolution of historical equipment problems. For those systems, structures, and components scoped in the maintenance rule per 10 CFR 50.65, the inspectors verified that reliability and unavailability were properly monitored, and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. Documents reviewed are listed in the Attachment.

- Repair of a packing leak on valve 2NS-18A; NS pump 2A suction from the containment sump

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the licensee's assessments concerning the risk impact of removing from service those components associated with the seven emergent and planned work items listed below. This review primarily focused on activities determined to be risk-significant within the maintenance rule. The inspectors also assessed the adequacy of the licensee's identification and resolution of problems associated with maintenance risk assessments and emergent work activities. The inspectors reviewed Nuclear System Directive (NSD) 415, Operational Risk Management (Modes 1-3), and NSD 403, Shutdown Risk Management (Modes 4,5,6, and No Mode), for appropriate guidance to comply with 10 CFR 50.65 (a)(4). Documents reviewed are listed in the Attachment.

- Rescheduling of the Unit 1 solid state protection system / reactor trip breaker testing due to delays in performance of the Unit 2 B Train essential safety feature testing.
- Identification of a leak on the Unit 2 reactor vessel head core exit thermocouple #76 and return to Mode 5.
- Review of scheduled surveillances during period of severe thunderstorm activity and rescheduling of quarterly Channel 4 Delta Temperature channel operational test.
- Turbine control system issues identified during the Unit 2 restart and delayed approach to criticality.
- Rescheduling of planned maintenance activities due to required surveillances associated with delay in the restart and power ascension of Unit 2 following the refueling outage.
- Review and rescheduling of planned work following the identification of a through-wall leak and additional piping degradation on the A and B main RN headers.
- Review and rescheduling of planned work following the identification of a through-wall leak on a weld on the 2A component cooling water heat exchanger RN discharge piping.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Plant Evolutions and Events

a. Inspection Scope

For the five events described below, the inspectors observed operator actions and reviewed operator logs and computer data to verify that proper operator actions were taken. The inspectors also observed licensed operators' use of procedures, control room pre-evolution briefings, and plant equipment manipulations during the reactor approach to criticality and performance of portions of zero power and startup physics testing. Documents reviewed are listed in the Attachment.

- Start-up of Unit 2 following the refueling outage
- Restart of Unit 2 following the repairs made to the core exit thermocouple nozzle assembly (CETNA) on the reactor vessel head.
- Notice of Unusual Event following the loss of offsite power and subsequent dual-unit reactor trip.
- Start-up of Unit 2 following the loss of off-site power event
- Start-up of Unit 1 following the loss of off-site power event

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed six operability evaluations to verify that the operability of systems important to safety were properly established, that the affected components or systems remained capable of performing their intended safety function, and that no unrecognized increase in plant or public risk occurred. Documents reviewed are listed in the Attachment.

- PIP C-06-2855; Fire Penetration J-AX-655-W-007 found to be degraded
- PIP C-06-2961; ND system support discovered pulled loose from the wall and subsequent testing identified additional repairs on supports required due to a water hammer event in the ND system
- PIP C-06-2320; Unexpected entry into Tech Specs due to a ground on the SSF diesel generator 74 relay and PIP C-06-3533; 600-volt ground detected on the SSF diesel circuitry
- PIP C-06-0197; NV pump 2B oil leak operability evaluation
- PIP C-06-1890; Main Steam Isolation Valve 2SM-005 did not indicate fully closed when the close pushbutton was depressed at the start of the 2EOC14 refueling outage
- PIP C-06-0809; Design parameters for FWST to ND pump suction isolation valves 1/2FW-27A and 1/2FW-55B do not consider realignment of the ND suction from Residual Heat Removal mode to injection mode in the event of a Mode 4 loss of coolant accident

b. Findings

No findings of significance were identified.

R17 Permanent Plant Modifications

.1 Resident Modification Review

a. Inspection Scope

The inspectors reviewed the following two permanent plant modifications to verify the adequacy of the modification packages, and to evaluate the modifications for adverse affects on system availability, reliability, and functional capability. Documents reviewed are listed in the Attachment.

- Nuclear Station Modification CN-CE-200902, Replacement of an ITT Barton 752S volume control tank level transmitter with a Rosemount 3051S level transmitter (Mitigating Systems)
  - Environmental qualification of the replacement transmitter
  - Control signals provided by the transmitter
  - Maintenance procedures for calibration of the transmitter
  - Equivalency review of new transmitter
- Nuclear Station Modification CN-21441/00, Installation of main steam isolation valve air close assist upgrades and associated air manifold (Mitigating Systems)
  - Environmental qualification of the piping and manifolds
  - Control signals used to actuate the air-assist system
  - Maintenance procedures for components of the air assist system
  - Reliability of the air source supplying the air manifold

b. Findings

No findings of significance were identified.

.2 Biennial Modifications Inspection

a. Inspection Scope

The inspectors evaluated five modifications, four commercial grade dedications, and three equivalency evaluations in the Mitigating Systems and Initiating Events cornerstone areas, to evaluate the modifications and materials/components replacements for adverse effects on system availability, reliability, and functional capability. The five modifications and the associated attributes reviewed are as follows:

- CN 21425, Replace EPK System Battery chargers with SCI Chargers (Mitigating Systems)
  - Seismic Qualification
  - Materials/ Replacement Components (conformance with design parameters)
  - Post-Modification Testing and Calibration
  - Environmental Evaluation
  - Plant Document Updating
  - Field Configuration Observation

- CN 21432, Replace Unit 2 B NSHX (Mitigating Systems)
- Material Certification and Evaluation
- Plant Document Updating
- Vendor Documents
- Field Observation
- Post-Modification Testing

- CD 50012, Increase RN Flow Setpoint and Decrease KC Temperature Mode Setpoint (Mitigating Systems)
  - System Flow Requirements
  - Post-Modification Testing Records

- CN 21441, Main Steam Isolation Valve (MSIV) Air Manifold Upgrades (Initiating Events)
  - Design Analysis
  - Plant Document Updating
  - Installation Records
  - Post-Modification Testing
  - Field Observation

- CN 21447, Unit 2 EDG Battery Replacement (Mitigating Systems)
  - Design Analysis
  - Post-Modification Testing
  - Installation Records
  - Plant Document Updating
  - Environmental Evaluation

The following commercial grade dedications (CGDs) and equivalency evaluations (CEs) were reviewed for material compatibility, functional properties, classification and environmental and seismic qualification:

- CGD 2012.01-04-0002, Evaluation of Chevron SRI-2 Grease
- CGD 2013.03-00-0001, Evaluation of Number 2 Diesel Fuel
- CGD 2018.04-00-0022, Power Element for AMOT Thermostatic Valve Model 8DAS
- CGD 3007.02-00-0003, Evaluation of GE CR151B4 Terminal Blocks.
- CE 500722, Allow Replacement of 1NMSV 2670 and Solenoid Valves
- CE 200211, Replace Controller 2CAML with Siemens 353 Controller
- CE 500594, Replace TDK Power Supply (fire detection system)

For the selected modification packages, the inspectors observed the as-built configuration. Documents reviewed included procedures, engineering calculations, modification design and implementation packages, work orders, site drawings, corrective action documents, applicable sections of the living UFSAR, supporting analyses, TSs, and design basis information.

The inspectors also reviewed selected PIPs and an assessment associated with modifications to confirm that problems were being identified at an appropriate threshold, entered into the corrective action process, and appropriate corrective actions had been initiated.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors witnessed and/or reviewed four post-maintenance testing procedures and/or test activities, as appropriate, for selected risk significant systems to verify if: (1) testing was adequate for the maintenance performed; (2) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents; (3) test instrumentation had current calibrations, range, and accuracy consistent with the application; (4) tests were performed as written with applicable prerequisites satisfied; and (5) equipment was returned to the status required to perform its safety function. Documents reviewed are listed in the Attachment.

- Post-maintenance operability test for the 2B diesel generator (PT/2/A/4350/0002B, Revision 84)
- Repair of leak found on Unit 2 reactor vessel head CETNA #76 identified during Mode 4 containment walkdown
- Repair of Unit 1 normal letdown valve (1NV-10) following the loss of off-site power event
- Post-maintenance test of the "A" control room area chiller following its failure to start automatically on the loss of offsite power event

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

.1 Unit 2 Refueling Outage

a. Inspection Scope

The inspectors evaluated following specific areas during Unit 2 refueling outage activities to ensure that the licensee considered risk in developing and implementing outage schedules; adhered to administrative risk reduction methodologies developed to control plant configuration; developed mitigation strategies for losses of key safety functions; and adhered to operating license and TSs requirements that ensure defense-in-depth. Documents reviewed are listed in the Attachment.

- management of configuration control and the risk associated with outage activities
- maintained defense-in-depth commensurate with the outage risk control plan for key

safety functions and applicable TS when risk-significant equipment was removed from service and that configuration changes due to emergent work and unexpected conditions were controlled in accordance with the outage risk control plan, and if control room operators were cognizant of plant configuration
- clearance tags were properly hung and that associated equipment was appropriately configured to support the function of the clearance and that the tags were properly removed when the equipment was returned to service
- reactor coolant system level and temperature instruments were installed and configured to provide accurate indication, and that instrumentation error was properly addressed including review and observation of lowering reactor water level activities.
- status and configurations of electrical systems for compliance with TS requirements and the licensee's outage risk control plan and that switchyard activities were controlled commensurate with safety and the licensee's outage risk control plan
- appropriate methods of decay heat removal were maintained throughout the outage as plant conditions and heat loads changed which included reviewing the updated Defense in Depth Assessment sheets, conducting walkdowns of in-plant equipment and the main control room panels, and discussing current and upcoming plant conditions with Operations and Outage Control Center personnel
- outage work was not impacting the ability of operators to operate the spent fuel pool cooling system during and after core offload
- reviewed flow paths, configurations, and alternative means for inventory addition to verify that they were consistent and maintained in accordance with the outage risk plan, and that reactor vessel inventory controls were adequate to prevent inventory loss.
- verify that proper reactivity control was maintained in accordance with the TS and Site Directive 3.1.30, Unit Shutdown Configuration Control (Modes 4,5,6 or No Mode), Revision 32, and NSD 403, Shutdown Risk Management (Modes 4, 5, 6 or No Mode), Revision 14.
- controlled containment penetrations in accordance with the refueling operations TS, and that containment closure could be achieved when needed
- reviewed the licensee's commitments from Generic Letter 88-17, Loss of Decay Heat Removal, to confirm that they were adequately implemented
- reviewed fuel handling operations to verify that they were performed in accordance with approved fuel handling procedures
- reviewed TS, license conditions, commitments, and administrative procedure prerequisites for mode changes to verify that they were met for changing plant configurations

b. Findings

No findings of significance were identified.

.2 Unit 1 Forced Outage

a. Inspection Scope

The inspectors evaluated Unit 1 forced outage activities following a loss of offsite power event to ensure that the licensee considered risk in developing and implementing outage schedules; adhered to administrative risk reduction methodologies developed to control plant configuration; developed mitigation strategies for losses of key safety functions; and adhered to operating license and Technical Specification requirements that ensure defense-in-depth. The following specific areas were reviewed:

- assessed the licensee's management of configuration control and the risk associated with outage activities
- reviewed reactivity control to verify that proper control was maintained in accordance with the TS and Site Directive 3.1.30, Unit Shutdown Configuration Control (Modes 4,5,6 or No Mode), Revision 32, and NSD 403, Shutdown Risk Management (Modes 4, 5, 6 or No Mode), Revision 14
- licensee controlled containment penetrations in accordance with the refueling operations TS, and that containment closure could be achieved when needed
- reviewed the licensee's commitments from Generic Letter 88-17, Loss of Decay Heat Removal, and confirmed that they were adequately implemented
- reviewed TS, license conditions, commitments, and administrative procedure prerequisites for mode changes to verify they were met for changing plant configurations

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed and/or reviewed the five surveillance tests listed below to verify that TS surveillance requirements and/or Select Licensee Commitment requirements were properly complied with, and that test acceptance criteria were properly specified. The inspectors verified that proper test conditions were established as specified in the procedures, that no equipment pre-conditioning activities occurred, and that acceptance criteria had been met. Additionally, the inspectors also verified that equipment was properly returned to service and that proper testing was specified and conducted to ensure that the equipment could perform its intended safety function following maintenance or as part of surveillance testing. Documents reviewed are listed in the Attachment.

Surveillance Tests
- PT/2/A/4200/013 H; NI and NV Check Valve Test, Revision 20
- IP/2/A/3200/001 B; Solid State Protection System Train B Periodic Testing, Revision 0
- PT/0/A/4400/022A; Nuclear Service Water Pump Train A Performance Test, Revision 74

In-Service Tests
- PT/1/A/4200/004C; Containment Spray Pump 1B Performance Test, Revision 60

Ice Condenser Systems Testing

- MP/0/A/7150/006; Ice Condenser Lower Inlet Door Inspection and Testing (As-left portion), Revision 25

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary plant modification to determine whether the modification was properly installed; the modification did not affect system operability; alarm responses, calculations and procedures were appropriately updated and the appropriate changes made to the alarm responses, calculations and procedures once the temporary modification was removed. Documents reviewed are listed in the Attachment.

- Revising the allowable #1 seal leakoff limit for the 1C reactor coolant pump to 5 gpm due to increased leakage through the seal and then returning the limit to its normal value following the seal replacement.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Daily Review

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed screening of items entered into the licensee's corrective action program. This was accomplished by reviewing copies of PIPs, attending some daily screening meetings, and accessing the licensee's computerized database.

.2 Annual Sample Review

a. Inspection Scope

The inspectors selected PIP C-06-0442 for detailed review. This PIP involved a loss of configuration control on 2RN-48B, nuclear service water crossover isolation valve, during a system modification. The piping downstream of the isolation valve was left open ended and the system was placed into operation without the 2RN-48B valve being danger tagged in the closed position to prevent inadvertent operation. The inspectors evaluated the PIP against the requirements of the licensee's corrective action program document and 10 CFR 50, Appendix B.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Review to Identify Trends

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of the licensee's Corrective Action Program (CAP) and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screenings discussed in section 4OA2.1 above, licensee trending efforts, and licensee human performance results. The inspectors' review primarily considered the six-month period of January 2006 through June 2006, although some examples expanded beyond those dates when the scope of the trend warranted. The review also included issues documented outside the normal CAP in major equipment problem lists, plant health team vulnerability lists, focus area reports, system health reports, self-assessment reports, maintenance rule reports, and Safety Review Group Monthly Reports. The inspectors compared and contrasted their results with the results contained in the licensee's latest quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensees trend report were reviewed for adequacy.

b. Findings and Observations

No findings of significance were identified. The inspectors followed the actions being implemented by the licensee in response to the inspector-identified trend associated with insufficient management oversight and control of vendors and contractors (non-station personnel). This trend statement was discussed in NRC Inspection Report 05000413, 414/2005005. Based on the inspectors' identification of this trend, the licensee concluded that a lack of guidance existed in NSD-105, Vendor Oversight and Control procedure. The licensee stated in corrective action documentation that this was evident in large projects undertaken during the recent service water project and at Oconee during the steam generator replacement project. Senior Management decided to incorporate specific decision points into the planning and approval process for major projects to ensure that oversight controls are considered and developed as part of an overall project development plan.

4OA3 Event Followup

Unit 1 and Unit 2 Loss of Offsite Power and Unit 1 A Diesel Generator Room Flooding

a. Inspection Scope

The inspectors observed the operators stabilize the two units following a loss of offsite power (LOOP) that occurred on May 20. The inspectors also responded to the 1A diesel generator room flooding that occurred on May 22. The inspectors discussed the events with the operators, engineering, and licensee management personnel to gain an understanding of the events and assess followup actions. The inspectors reviewed the licensee's initial investigation reports and cause determinations. The licensee's initial cause determination for the LOOP identified a power circuit breaker current transformer failure due to a fault. An NRC augmented inspection was initiated on May 23 in response to these two events. The results of the augmented inspection were documented in NRC Inspection Report 05000413/2006009 and 05000414/2006009. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI): 05000413,414/2006009-04; Review the Extent of Condition and Corrective Actions to Address Degraded Seals on Below-Grade Electrical Conduits Entering the Auxiliary Building

Introduction: A Green NCV of Technical Specification 5.4.1.b, for failure to adequately establish and implement procedures required by Regulatory Guide 1.33, Appendix A, Section 9, Procedures for Performing Maintenance, was identified. Specifically, no procedure, program, or process existed to periodically inspect below-grade electrical conduit seals to identify and repair any degradation of seals which provide protection of safety-related equipment from external flooding.

Description: Much of the plant's electrical cables were buried underground and routed in conduits between manhole structures and plant structures such as the auxiliary building and diesel generator building. The electrical conduits that entered the plant structures were sealed using a silicone-based sealant in the manhole structure located closest to the specific plant structure. The silicone sealant had a finite lifetime specified by the sealant manufacturer.

On May 22, the 1A diesel generator room flooded due to cooling tower overflow water entering the underground electrical conduits through unsealed electrical conduit penetrations. As a result of this event, other electrical conduits entering the auxiliary and diesel generator buildings were inspected to verify that the required seals had been installed and their ability to prevent flooding of the plant structures from external sources had not been degraded.

The inspectors conducted an inspection of these conduit seals accompanied by engineers from the licensee's staff. Upon entering Conduit Manholes CMH-18A and CMH-18B, a number of seals were found to be degraded or not sealed in accordance with the licensee's design drawings or procedures. Work orders were initiated to have the conduits repaired and properly sealed. NRC inspections of other conduits entering areas of the plant containing safety-related equipment identified additional seals that required repairs to re-establish their integrity and waterproof function.

Following discussions with the engineers and maintenance personnel responsible for the electrical conduits at the station, it was determined that there were no programs, processes or procedures in place to periodically inspect the seals of below-grade electrical conduits for degradation or damage which could adversely affect their ability to prevent external flooding from reaching areas of the plant containing safety-related equipment.

Analysis: The finding was more than minor because the condition could have become more of a safety concern if uncorrected, i.e., additional degradation of the conduit seals would have occurred over time thereby increasing the potential for external flooding affecting safety-related equipment. The inspectors determined the finding to be of very low safety significance because the as-found condition of the conduit seals would not have resulted in the loss or degradation of safety-related equipment in the event of a Probable Maximum Precipitation event.

Enforcement: Technical Specification 5.4.1.b requires that written procedures as described in Regulatory Guide 1.33, Revision 2, Appendix A, be established, implemented, and maintained. Regulatory Guide 1.33, Appendix A, Section 9, Procedures for Performing Maintenance, Sub-Section b, requires that preventive maintenance procedures and schedules be developed to include inspections of equipment and replacement of items that have a specific lifetime. Contrary to the above, on May 26, 2006, the NRC determined that the licensee failed to establish and implement a preventive maintenance procedure and schedule to inspect the installation and integrity of silicone seals with a finite lifetime in below-grade electrical conduits designed to protect safety-related areas of the plant from external flooding. Because this violation was determined to be of very low safety significance and was placed in the corrective action program as PIP C-06-3902, this violation is being treated as a non-cited violation in accordance with Section VI.A.1 of the Enforcement Policy, and is identified as NCV 05000413,414/2006003-01, Failure to Establish Periodic Inspection Procedures for Seals on Below-Grade Electrical Conduits Entering Plant Areas Containing Safety-Related Equipment.

.2 (Closed) URI 05000413,414/2006009-01, Timeliness of Notification to the NRC of Loss of Offsite Power Event on May 20, 2006

The inspectors reviewed this issue involving late notification of a loss of offsite power. The loss of offsite power was classified by the licensee as an Unusual Event at 2:14 p.m. However, the NRC Operations Center was not notified of the classification until 4:15 p.m. The inspectors concluded that the licensee was required to notify the NRC within one hour following the classification of this event. The inspectors reviewed the licensee's Emergency Response Organization post-event self-evaluation report. The licensee had identified, during the event response, that they had missed the notification. The licensee immediately made the required notification when they determined that they had missed the time requirement and informed the Technical Support Center Emergency Coordinator that the 1-hour event notification had been made over one hour late. The inspectors reviewed the Technical Support Center log and conducted interviews with the Emergency Response Organization staff who were on duty the day of the event. The inspectors concluded that this was a violation of NRC requirements and that it was a licensee-identified violation. The enforcement aspects of this violation are dispositioned in Section 4OA7.

.3 (Closed) NRC Temporary Instruction (TI) 2515/165: Operational Readiness of Offsite Power and Impact on Plant Risk

The inspectors reviewed licensee procedures and controls and interviewed operations and maintenance personnel to verify these documents contained specific attributes delineated in the TI to ensure the operational readiness of offsite power systems in accordance with plant Technical Specifications; the design requirements provided in 10 CFR 50, Appendix A, General Design Criterion 17, "Electric Power Systems," and the impact of maintenance on plant risk in accordance with 10 CFR 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Appropriate documentation of the results of this inspection was provided to NRC headquarters staff for further analysis, as required by the TI. This completes the Region II inspection TI requirements for the Catawba Nuclear Station.

4OA6 Meetings, Including Exit

On July 12, the resident inspectors presented the inspection results to Mr. D. Jamil and other members of licensee management, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection period.

4OA7 Licensee-Identified Violation

The following finding of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a non-cited violation.

10 CFR 50.72(a)(3) requires the licensee to notify the NRC Operations Center of the declaration of any of the Emergency Classes specified in the licensee's approved Emergency Plan immediately after notification of the appropriate State and local agencies and not later than one hour after the time entry into the Emergency Class was declared. Contrary to this, on May 20, 2006, the licensee declared a Notice of Unusual Event at 2:14 p.m. following the loss of offsite electrical power to both Catawba units with onsite power available; however, the NRC Operations Center was not notified until 4:15 p.m. which was 61 minutes late. This issue is documented in the licensee's corrective action program as Problem Investigation Process Report (PIP) C-06-3916.

This finding was of very low safety significance because the Resident Inspectors were contacted within 15 minutes of the actual loss of offsite power, promptly responded to the site, and informed Regional and Headquarters personnel of the details of the event upon their arrival and provided updates as plant conditions changed.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
K. Adams, Human Performance Manager
E. Beadle, Emergency Planning Manager
S. Beagles, Chemistry Manager
W. Byers, Security Manager
J. Ferguson, Safety Assurance Manager
J. Foster, Radiation Protection Manager
W. Green, Reactor and Electrical Systems Manager
G. Hamrick, Mechanical, Civil Engineering Manager
D. Jamil, Catawba Site Vice President
R. Hart, Regulatory Compliance Manager
A. Lindsay, Training Manager
J. Pitesa, Station Manager
L. Reed, Modifications Engineering Manager
R. Repko, Engineering Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000413,414/2006003-01	NCV	Failure to Establish Periodic Inspection Procedures for Seals on Below-Grade Electrical Conduits Entering Plant Areas Containing Safety-Related Equipment (Section 4OA5.1)

Closed

05000413,414/2006009-04	URI	Review the Extent of Condition and Corrective Actions to Address Degraded Seals on Below-Grade Electrical Conduits Entering the Auxiliary Building (Section 4OA5.1)
05000413,414/2006009-01	URI	Timeliness of Notification to the NRC of Loss of Offsite Power Event on May 20, 2006 (Section 4OA5.2)
05000413,414/2515/165	TI	Operational Readiness of Offsite Power and Impact on Plant Risk (Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Preparations
PT/0/B/4700/039; Hot Weather Preparation, Revision 09

PT/0/B/4700/038; Cold Weather Protection; Revision 25
PIP C-05-3736; Hot weather preparation issues raised by NRC residents
PIP C-05-3124; Revision to Hot Weather Preparation procedure required
Hot Weather Program Action Register Update; 6/27/06

Section 1R02: Evaluation of Changes, Tests, or Experiments

Full Evaluations

CNTM 0159, 1RN-4B removed from RN system, 8/20/04
Procedure change OP/1/A/6400/006 RN inlet to NS Hx flush - Encl. 4.23, 4/1/04
CN-21432/01 NS HX 2B replacement, 7/19/04
Evaluate Spring only PORV Stroke time requirement - PT/1/2(2)/A/4200/023A, 10/5/04
PIP C04-0114 Operable but degraded eval - NS Hx 2A degraded baffle condition, 2/19/04
Change exercising frequency for RF 389B from quarterly to cold shutdown, 11/9/04
CNCE -62336, Install surge protection on FWST level instr. Loops, 5/20/04
CNCE-61427, Modify EDG 2A lube oil supply tubing to turbo charger, 10/11/04

Screened Out Items

CNCE 11024, Remove honeycomb straightening vanes from monitor 1ABUX-AFMD-1
CNCE 71104, Replace Unit 1 36V Lamda power supply , 6/10/02
CNCE 72586, Replace 2B gear drive oil pressure relief valve, 3/31/04
CNCE 72645, Replace fuses for RA-8 and RA-9, 12/10/03
CNCE 72884, Revise NI and NV TAC sheets. Flow balance procedures will be affected, 5/27/04
CNCE 73039, Revise 2LPPS5040 and 2LPPS5050 setpoints, 4/6/04
CNCE 73044, Replace 1NWLT5020 with Rosemount model, 3/4/04
CNCE 73069, Revise TAC sheets for KC Hx to reflect CNC-1223.24-00-0018, 4/21/04
CNCE 73074, Allow use of square D custom built multitap transformer for U2 battery fan, 3/9/04
CN 21441/00, MSIV air manifold upgrades , 01/25/06
CNCE 62368, Aux contact for valve EMOs fed from 2EXMA, 8/8/05
CD 200108, SWP install 30" U2 crossover line in aux bldg., 11/16/05
CD 200323, Relocate valves 2CA-57 and 2CA-61, 10/24/05
CD 100262, Relocate valves 1CA-57 and 1CA-61, 6/13/05
CD 200494, Replace lube oil piping on 2B EDG, 12/14/05
CN 21447, Unit 2 EDG Battery Replacement, 10/18/05

Self-Assessment Documents

NSRB 10 CFR 50.59 Evaluation Subcommittee Meeting Minutes, 9/15/05
10 CFR 50.59 Screens and Evaluations Assessment RGC-01-05, 1/10/2005 - 2/10/2005
10 CFR 50.59 Screens and Evaluations Assessment RGC-07-05, 9/10/2005 - 10/10/2005
10 CFR 50.59 Screens and Evaluations Assessment RGC-01-06, 9/10/2005 - 12/20/2005

Section 1R04: Equipment Alignment

OP/2/A/6200/006, Revision 055; Safety Injection System, Enclosure 4.3 Valve Checklist
CN-2562-1.0, 1.1, 1.2 and 1.3; Flow Diagrams of Safety Injection System
CNS-1562.NI-00-0001, Revision 32; Design Basis Specification for the Safety Injection System
Technical Specifications Emergency Core Cooling System: 3.5.2, 3.5.3, and 3.5.4
Safety Injection Health Report, 2005T3

PIP C-06-02793; Documented two problems with 2NI-9A
W/O 98373981

Section 1R05: Fire Protection
Pre-Fire Plan for Fire Strategy Area RB-1; Unit 2 Reactor Building, Annulus Area Only
Pre-Fire Plan for Fire Strategy Area 50; Unit 2 Exterior Doghouse
Pre-Fire Plan for Fire Strategy Area 1; Unit 1 A and B ND pump rooms
Pre-Fire Plan for Fire Strategy Area 41, Diesel Generator Building 1A Corridor
Pre-Fire Plan for Fire Strategy Area 25, Diesel Generator Building Room 1A
Pre-Fire Plan for Fire Strategy Area 41, Diesel Generator Building 1A Corrido
Pre-Fire Plan for Fire Strategy Area 4; Auxiliary Building 543 foot elevation, Rooms 200 to 248
Pre-Fire Plan for Fire Strategy Area 32; Auxiliary Building 543 foot elevation, Room 252; Unit 1A Auxiliary Shutdown Panel
Pre-Fire Plan for Fire Strategy Area 34; Auxiliary Building 543 foot elevation, Room 253; Unit 1B Auxiliary Shutdown Panel

Section 1R07: Heat Sink
PIP C-06-4604; ; 2B NS heat exchanger unadjusted fouling factor was less than the administrative limit of 0.000

Section 1R08: Inservice Inspection Activities
Procedures
NDE-600, Ultrasonic Examination of Similar Metal Welds in Ferritic and Austenitic Piping, Revision 16
NDE-35, Liquid Penetrant Examination, Revision 21
PT/2/A/4150/001 H, Inside Containment Boric Acid Check, Revision 13
PT/2/A/4150/002, Visual Inspection of Radioactive Systems Outside Containment, Revision 21
MP/0/A/7650/040, Inspection, Evaluation and Cleanup of Boric Acid on Plant Materials, Revision 9
SGMEP 105, Model D5 Specific Assessment of Potential Degradation Mechanisms for Catawba Unit 2 EOC 14, Revision 5
Condition Monitoring and Operational Assessment for Catawba Unit 2 EOC 13
D5 Steam Generator Site Technique Validation for Catawba Nuclear Station Unit 2, Revision 4
OP/2/B/6150/010, Loose Parts Monitoring Program, Revision 15
CMP 3.4.17.2, Secondary Chemistry, Revision 35
SCM-8 Appendix A, System Chemistry Manual "Catawba Secondary Chemistry Optimization Plan," Revision 9

PIPs: C-06-02444, C-06-02346, C-06-02134, C-06-02321, C-06-02236, C-05-04865, C-06-01876, C-06-02442, C-06-02499, C-04-05114, C-06-00838

Reports
Wesdyne Report for 10-year Inservice Inspection of Reactor Vessel Welds (welds 2RPV-101-124B, -142A, and -142C, and -171)
RT Examination Report/Technique for welds 2NC 9-03 and 2SGA-Outlet-SE
UT Examination Reports UT-06-121 through -128 (welds 2NI89-6, -7, -10, and -11)
UT Calibration Reports CAL-06-128 through -130 (welds 2NI89-6, -7, -10, and -11)

PT Examination Reports PT-06-115 through -119 (welds 2NC-89-4, -20, -21, -12, and -13)
Weld Process Control Record for Work Order: 98631591 (weld 2BB61-23-1)
Weld Process Control Record for Work Order: 98717523 (weld 2492-NS.00-46-18-1)
Weld Process Control Record for Work Order: 98731479 (weld 2CA62-12)
SGM 2005-001, Oconee Steam Generator Management Program Group Self Assessment
2005Q3Q4, Catawba Secondary Chemistry Systems Health Report

Section 1R11: Licensed Operator Requalification
NRC Graded Exercise Guide, May 16, 2006

Section 1R12: Maintenance Effectiveness
PIP C-06-2560; Rework associated with 2NS-18A

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation
PIP C-06-2888; Need to reschedule the Unit solid state protection system / Reactor Trip Breaker test due to delays in performing the Unit 2 B Train ESG test during 2EOC14
PIP C-06-3019; CETNA #76 was found to be leaking during the Mode 4 walkdown of the reactor head area
PIP C-06-3076; Continuing leakage noted on CETNA #76
PIP C-06-3110; Thurstorms in the area delayed surveillances
PIP C-06-3175; Main turbine stop valve SV-2 failed open during turbine chest and shell warming
PIP C-06-3812; Through wall leak discovered on the A RN train near the 2A component cooling water heat exchanger resulting in an unanticipated TSAIL entry for A train of RN on both units.
OMP 2-18; Equipment Protection and Quarantine Procedure; Revision 66

Section 1R14: Operator Performance During Non-Routine Plant Evolutions and Events
PT/0/A/4150/019; 1/M Approach to Criticality; Revisions 29, 30, and 31
PT/0/A/4150/001J, Zero Power Physics Testing; Revision 01
PT/0/A/4150/001, Controlling Procedure for Startup Physics Testing; Revision 40
OP/1/A/6100/001, Controlling Procedure for Unit Startup; Revision 211
OP/2/A/6100/001, Controlling Procedure for Unit Startup; Revision 141
OP/2/A/6100/003, Controlling Procedure for Unit Operations; Revision 97
OP/2/B/6300/001, Turbine Generator Startup; Revision 69
OP-CN-JITT-ZPPT/Turbine; Just In Time Training Package; Initial Startup / Zero Power Physics Testing / Turbine On-Line; Revision 03
EP/1/A/5000/ES-0.2; Natural Circulation Cooldown; Revision 19
AP/1/A/5500/007; Loss of Normal Power; Revision 49
EP/1/A/5000/ECA-0.1; Loss of all AC Power Recovery Without SI Required; Revision 21
EP/1/A/5000/E-0; Reactor Trip or Safety Injection; Revision 27
EP/1/A/5000/ES-0.1; Reactor Trip Response; Revision 22
AP/1/A/5500/012; Loss of Charging or Letdown; Revision 23
EP/2/A/5000/ES-0.1; Reactor Trip Response; Revision 22
EP/2/A/5000/E-0; Reactor Trip or Safety Injection; Revision 26
EP/2/A/5000/FR-I-1; Response to High Pressurizer Level; Revision 11
AP/2/A/5500/012; Loss of Charging or Letdown; Revision 19
AP/2/A/5500/007; Loss of Normal Power; Revision 49
Plant Unified Operational Logs for Unit 1 and Unit 2; Covering 5/20/06 through 5/25/06

Section 1R15: Operability Evaluations
PIP C-01-3425; Support found damaged by an apparent water hammer load condition
TSAIL entry C2-06-00802; 2B ND inoperable due to water hammer

Section 1R17: Permanent Plant Modifications
Minor Mod / Equivalent, Graded & Minor Design Change Package for CE200902; Replacement volume control tank level transmitter - Major Design Change CN-21441; Main Steam Isolation Valve air manifold single failure and air assist upgrades

Section 1R19: Post-Maintenance Testing
PIP C-06-3019; CETNA #76 was found to be leaking during the Mode 4 walkdown of the reactor head
WO 98735228; Repair of leak on Unit 2 CETNA #76
WR 98375994; Failure of valve 1NV-10 to open following loss of off-site power transient
PIP C-06-4037; Failure of the A control room area chiller to start automatically following the loss of offsite power
WO 98791173; Inspect / Repair the A control room area chiller

Section 1R20: Refueling and Outage Activities
Site Directive 3.1.30, Unit Shutdown Configuration Control (Modes 4, 5, 6 or No Mode), Revision 32,
Operations Procedure OP/2/A/6150/006, Draining The Reactor Coolant System, Revision 68
CN-06-006, 2EOC-14-IRT (Ipendent Review Team) Outage Risk Assessment
PT/2/A/4350/003, Electrical Power Source Alignment Verification, Revision 44
OP/2/A/6200/005, Spent Fuel Cooling System, Revision 61
NSD 403, Shutdown Risk Management (Modes 4, 5, 6 or No Mode), Revision 14
PT/2/A/4200/002C, Containment Closure Verification (Part I); Revision 62
PT/2/A/4200/002I, Containment Closure Verification (Part II); Revision 34
PT/2/A/4200/002J, Containment Closure Verification Penetration Status Change; Revision 12
OP/0/A/6100/014, Penetration Control for Modes 5 and 6; Revision 30
OP/2/A/6150/001, Filling and Venting the Reactor Coolant System, Enclosure 4.16, Reactor Coolant System Vacuum Refill Without Solid Operation; Revision 72
OP/2/A/6150/006, Draining the Reactor Coolant (NC) System; Revision 68
Enclosure 4.2, Decreasing the NC System Level;
Enclosure 4.3, Increasing the NC System Level
Enclosure 4.10, Requirements for Operation with the NC System Level Below 16%
Enclosure 4.12; Reduced Inventory Posting Requirements
PT/0/A/4150/037, Fuel/Component Movement Accounting; Revision 6
OP/2/A/6550/006, Transferring Fuel with the Spent Fuel Manipulator Crane; Revision 49
OP/2/A/6550/007, Reactor Building Manipulator Crane Operation; Revision 24
OP/2/A/6550/008, Fuel Transfer System Operation; Revision 9
(Maintenance Procedure) MP/0/B/7150/012, Refueling Canal Cleanliness; Revision 07
PT/2/A/4550/001C, Refueling Communications Test; Revision 15
PT/2/A/4550/001D; Reactor Building Manipulator Crane Load test; Revision 12
PT/2/A/4550/001E; Spent Fuel Building Manipulator Crane Load test; Revision 7
PT/0/A/4550/003C, Core Verification; Revision 09
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Unit 2 2EOC14 Core Reload Verification videotape
PT/0/A/4200/002, Containment Cleanliness Inspection; Revision 25
SM/0/A/8510/008, Ice Condenser FME Inspection; Revision 3
PT/0/A/4150/019; 1/M Approach to Criticality; Revision 29
PT/0/A/4150/001J, Zero Power Physics Testing; Revision 01
PT/0/A/4150/001, Controlling Procedure for Startup Physics Testing; Revision 40
OP/2/A/6100/001, Controlling Procedure for Unit Startup; Revision 141
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PT/1/A/4200/002J, Containment Closure Verification Penetration Status Change; Revision 10
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OP/1/A/6150/001, Filling and Venting the Reactor Coolant System, Enclosure 4.16, Reactor Coolant System Vacuum Refill Without Solid Operation; Revision 95
OP/1/A/6150/006, Draining the Reactor Coolant System; Revision 68
Enclosure 4.2, Decreasing the NC System Level;
Enclosure 4.3, Increasing the NC System Level
Enclosure 4.10, Requirements for Operation with the NC System Level Below 16%
Enclosure 4.12; Reduced Inventory Posting Requirements
PT/0/A/4200/002, Containment Cleanliness Inspection; Revision 26
PT/0/A/4150/019; 1/M Approach to Criticality; Revision 31
OP/1/A/6100/001, Controlling Procedure for Unit Startup; Revision 211
OP/1/A/6100/003, Controlling Procedure for Unit Operations; Revision 97
OP/1/B/6300/001, Turbine Generator Startup; Revision 69
SM/0/A/8510/002; Ice Basket Inspection, Revision 009
PIP C-06-2987; Documentation of the Unit 2 containment cleanliness PT conducted by Operations
PIP C-06-3056; During Unit 2 main turbine shell warming, a turbine control system malfunction caused a rapid steam generator pressure reduction and reactor coolant system cooldown which resulted in pressurizer pressure decreasing to approximately 2000 psig and level to 18%

Section 1R22: Surveillance Testing
PIP C-06-02743; Performance of NI/NV Check Valve Test PT/2/a/4200/013 H
PIP C-06-02744; Procedures PT/2/A/4200/007A, PT/2/A4200/005B, PT/2/A/4200/005A need to be revised to incorporate new baseline data that was obtained during performance of NI/NV check valve testing
PIP C-06-02745; The desired flow for obtaining comprehensive IWP data for the 2A and 2B NV pumps and 2B NI pump could not be established during NI/NV check valve testing
PIP C-06-02793; Documented two problems with 2NI-9A
PIP C-06-03112; Outage Critique items concerning PT/2/A/4200/013 H Check Valve Test, and associated activities

Section 1R23: Temporary Plant Modifications
CD 100932; Engineering Change to revise the SSF upper limits for the Unit 1 NC Pump #1 seal

leakoff
CD 100991; Engineering Change to restore NC pump #1 seal leakoff flow limits to normal

Section 4OA2: Problem Identification and Resolution
Safety Review Group Monthly Reports - December 2005-May 2006
PIP C-05-3748; Human Performance Cause Analysis

Section 4OA3: Event Follow-up
PIP C-06-4087; Drawings show unused conduits being stubbed and capped; however, the NRC Resident identified that in many cases, the actual conduits to not reflect that configuration in the field
PIP C-06-4112; Degraded conduit seals identified by the NRC Resident in conduit manholes CMH-18A and CMH-18B
PIP C-06-4663; NRC Resident identified discrepancies between field conditions and drawings associated with conduit manhole CMH-7B
PIP C-06-4884; Incorrect level switches and a buried sump pump drain line associated with three Conduit Manholes
PIP C-06-4887; As-Built / drawing discrepancies in conduit manholes CMH-3, CMH-4A and CMH-5B identified by the NRC Resident during inspections

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

June 29, 2006

Duke Energy Corporation
ATTN: Mr. D. M. Jamil
Site Vice President
Catawba Site
4800 Concord Road
York, SC 29745-9635

SUBJECT: CATAWBA NUCLEAR STATION - NRC AUGMENTED INSPECTION TEAM (AIT) REPORT 05000413/2006009 AND 05000414/2006009

Dear Mr. Jamil:

On May 26, 2006, the U. S. Nuclear Regulatory Commission (NRC) completed an Augmented Inspection at your Catawba Nuclear Station, Units 1 and 2. The enclosed report documents the inspection findings, which were preliminarily discussed on May 26 with you and other members of your staff. A public exit was conducted with you and members of your staff on May 31, 2006.

The events that led to the conduct of the Augmented Inspection can be summarized as follows:

> On May 20, 2006, at approximately 2:01 p.m. EDT, a phase-to-ground electrical fault on a current transformer in the 230kV switchyard associated with the Catawba Unit 1 main step-up transformer 1A initiated a sequence of events that resulted in a Loss of Offsite Power (LOOP) event for both Unit 1 and Unit 2. A tap setting on bus differential relaying for the "Red" and "Yellow" busses within the "breaker-and-a-half" switchyard configuration scheme, which had been set incorrectly since prior to the initial commercial operation of the plant, was a major contributory element to this event.
>
> On May 22, 2006, a second event, unrelated to the first, occurred as preparations were being made to restore the secondary-side plant on Unit 2 and return secondary-side heat removal to the steam dumps from the steam generator power operated relief valves. Water overflowing from the Unit 2 cooling towers traveled through unsealed electrical conduits in cable trenches and manholes and entered the 1A diesel generator room, resulting in the 1A diesel generator being declared inoperable.

Based on the risk and deterministic criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," and the significance of these operational events, an NRC Augmented Inspection Team (AIT) was dispatched to the site on May 23, 2006 in accordance with Inspection Procedure 93800, "Augmented Inspection Team." The purpose of the inspection was to evaluate the facts and circumstances surrounding the events, as well as the actions taken by your staff in response to the events. The inspection focus areas are detailed in the Augmented Inspection Team Charter (Attachment 5). The team reviewed your immediate and planned corrective actions prior to restart, including your actions to improve the independence and reliability of offsite power sources, and found those actions appropriate for continued operation of the units. The team found some issues which will require additional inspection followup. These issues are identified as unresolved items in the report.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Charles A. Casto, Director
Division of Reactor Projects

Docket Nos.: 50-413, 50-414
License Nos.: NPF-35, NPF-52

Enclosure: NRC Inspection Report 05000413/2006009 and 05000414/2006009
w/Attachments: Supplemental Information

cc w/encl: (See page 3)

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-413, 50-414
License Nos.:	NPF-35, NPF-52
Report Nos.:	05000413/2006009 and 05000414/2006009
Licensee:	Duke Energy Corporation
Facility:	Catawba Nuclear Station, Units 1 & 2
Location:	4800 Concord Road York, SC 29745
Dates:	May 23 - 31, 2006
Team Leader:	James H. Moorman, III, Chief Operations Branch Division of Reactor Safety
Inspectors:	L. Cain, Resident Inspector, V.C. Summer N. Merriweather, Senior Reactor Inspector A. Sabisch, Resident Inspector, Catawba W. Lewis, Reactor Inspector
Approved by:	Charles A. Casto, Director Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000413/2006009, 05000414/2006009; 5/23-31/06; Catawba Nuclear Station, Units 1 and 2; Augmented Inspection.

This inspection was conducted by a team consisting of inspectors from the NRC's Region II office and resident inspectors from the Catawba and V.C. Summer Nuclear Stations. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000. An Augmented Inspection Team was established in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program" and implemented using Inspection Procedure 93800, "Augmented Inspection Team."

A. <u>NRC-Identified and Self-Revealing Findings</u>

To be determined through the Reactor Oversight Program review of this report.

B. <u>Licensee Identified Findings</u>

None.

An NRC Augmented Inspection Team was dispatched to the site on May 23 to review the loss of offsite power (LOOP) event and the partial flooding of the 1A diesel generator (DG) room. The team found that the licensee's response to the LOOP event and to the partial flooding of the 1A DG room was generally acceptable. The team identified four issues for inspection followup. These issues are tracked as unresolved items in this report.

REPORT DETAILS

Summary of Plant Events

On May 20, 2006, at 2:01 p.m., an electrical fault in the Catawba 230kV switchyard caused several power circuit breakers (PCB's) to open resulting in a loss of all offsite power (LOOP) and a subsequent reactor trip of both units from 100 percent power. All reactor trip breakers opened as expected and all control rods fully inserted into the core on the two units. Both main turbines tripped upon receipt of the P4 protective signals following the reactor trips. Control room operators responded to the event using normal, abnormal and emergency operating procedures.

Following the LOOP, the four (4) emergency diesel generators started and supplied power to the 4.16kV vital busses. Designated vital equipment was re-energized in accordance with the plant design through the diesel generator load sequencers.

A Notice of Unusual Event (NOUE) was declared at 2:14 p.m. on May 20, 2006, due to the loss of AC electrical power from all offsite sources for more than 15 minutes with onsite power available. The Technical Support Center (TSC), Operations Support Center (OSC), and subsequently the Emergency Operations Facility (EOF) were all activated on a precautionary basis to provide support as required.

Power was restored to the Unit 2 6.9kV busses at 8:27 p.m. on May 20, 2006, and to the Unit 1 6.9kV busses at 8:40 p.m. Due to existing lockouts on the 1A and 2B main transformers, full realignment of breakers to provide offsite power to the vital busses and securing of all four diesel generators did not occur until approximately 1:10 a.m. on May 21, 2006. The NOUE was terminated at 1:45 a.m. on May 21, 2006.

In an unrelated event, on May 22, 2006, water overflowing from the Unit 2 cooling towers due to clogged screens entered the 1A diesel generator (DG) room through unsealed electrical conduits resulting in the 1A DG being declared inoperable. Following conduit seal repairs, inspection of DG support equipment and functional testing, the 1A DG was returned to operable status on May 24, 2006.

Inspection Scope

Based on the probabilistic risk and deterministic criteria specified in Management Directive 8.3, “NRC Incident Investigation Program,” Inspection Procedure 71153, “Event Followup,” and the significance of the operational events which occurred, an Augmented Inspection was initiated in accordance with Inspection Procedure 93800, “Augmented Inspection Team.”

The inspection focus areas included the following charter items:

- Develop a complete sequence of events, including applicable management decision points, from the time the LOOP occurred until both units were stabilized.

- Identify and evaluate the effectiveness of the immediate actions taken by the licensee in response to this event including the accuracy and timeliness of the licensee's classification of the event.

- Identify additional actions planned by the licensee in response to this event, including the time line for their completion of the investigation and follow-on analysis.

- Assess the circumstances surrounding the multiple lifting and reseating of the Unit 1 and Unit 2 pressurizer power operated relief valves.

- Determine if there are any generic issues related to this event which warrant an additional NRC response. As part of this review, assess the implications of a common cause failure of the emergency diesel generators due to external flooding. [Added to the charter after the May 22 event.] Promptly communicate any potential generic issues to regional management.

4. OTHER ACTIVITIES

4OA5 Augmented Inspection (93800)

.1 Develop a complete sequence of events, including applicable management decision points, from the time the LOOP occurred until both units were stabilized.

a. Inspection Scope

For the purposes of this Augmented Inspection, the team divided the charter element into three separate sequences of events; 1) electric plant response, 2) integrated plant response and 3) Emergency Response Organization response. The inspection team reviewed unified control room logs, operator aid and plant computer alarm and data logs, sequence of event recorder reports, and an event chronology developed by licensee personnel. The inspection team also interviewed several licensee and Duke Energy Power Delivery Department (i.e., Transmission) personnel in order to validate and further establish the sequence of events.

For the purpose of this inspection, "Unit Stabilization" was defined as follows:

- Electrical systems response - All diesels running, the load sequencer operation completed and safety loads re-energized from the diesel generators.
- Integrated plant response - Unit 1 stabilized in Mode 5 on Residual Heat Removal (ND) due to issues related to reactor coolant pump motor cooling caused by biological debris fouling. Unit 2 stabilized in Mode 3 with forced circulation and secondary side heat removal restored to the main condenser via steam dumps.
- Emergency Organization response - Termination of the Notice of Unusual Event.

b.1 Electrical Systems Response:

A list of the significant electrical plant events and time stamps is provided in Attachment 8, "Electrical Plant Sequence of Events."

On 20 May 2006 at 2:01 p.m. EDT, a phase-to-ground electrical fault within the current transformer (CT) on the Catawba Unit 1 main step-up transformer 1A line position occurred within the 230kV switchyard resulting in a Loss of Offsite Power (LOOP) event for both Unit 1 and Unit 2. The entire sequence of events progressed so rapidly as to preclude any possible operator response to prevent the end result, but the sequence of events is presented in order to facilitate its understanding.

Actual Electrical Plant Response to the Event (See the simplified diagram of the Catawba main generator, transformers, and switchyard in Attachment 6 for specific breaker and relay locations):

The initial event that occurred was an internal fault in the X-phase CT associated with Power Circuit Breaker (PCB) 18.

Initial indications of neutral overcurrent (74TM) on all four main step-up transformers and overcurrent on both generators' X and Z phase windings were received by the plant computer. Fault protection provided by the Unit 1 A main step-up transformer differential protective relaying, as well as bus differential protective relaying actuated, resulting in the following breakers opening:

- Yellow bus (87BY) differential - PCB's 15, 18, 21, 24, 27, 30 and 33 (*)
- Red bus (87BR) differential - PCB's 10, 13, 16, 19, 22, 25, 28 and 31
- Zone 1A (86A) lockout - PCB's 18 (repeat signal), 17 and Main Generator Circuit Breaker (GCB) 1A

* It could not be confirmed that PCB 12 opened during the event. The breaker was subsequently demonstrated to be able to cycle by both Transmission System and Catawba Nuclear Station personnel. The station's corrective action program was scheduled to conduct additional testing and relay checks to verify that the breaker is fully functional.

The X-phase CT fault on PCB 18 induced a subsequent fault on the secondary side coils of the Y-phase CT associated with PCB 23. This coil provides an input to the Unit 2 B main step-up transformer differential protective relaying and resulted in its actuation causing the following breakers opening:

- Zone 2B (86B) lockout - PCB's 23, 24 (repeat signal) and GCB 2B

Both units received a runback signal which would have reduced electrical output to 48% as designed; however, this rapid sequence of events left Unit 1 attempting to feed 100% of its output through PCB 14 to the Newport Tie Station down the Allison Creek Black transmission line. This line was designed to carry 56% of rated station output (one hour summer rating). The Allison Creek Black line remote end breaker tripped at the Newport tie-station on over current and PCB 14 tripped open approximately 18 seconds later. The exact cause of the PCB 14 breaker trip was still under investigation.

Unit 2 was attempting to feed 100% of its output through PCB 20 to the Pacolet Tie Station down the Roddey Black transmission line. This line was designed to carry 56% of rated station output (one hour summer rating). The Roddey Black line distance (21) relay actuated, opening the remote end breakers and tripping PCB 20.

The Unit 1 and Unit 2 blackout logic was initiated upon loss of the 4.16kV bus because undervoltage conditions existed on all four of the vital electrical busses. All four diesel generators received auto-start signals. They were loaded by the blackout load sequencers and the safety loads were loaded back onto the vital busses and re-energized in their designated load groups per design.

Design Electrical Plant Response to the Event:

If the actual relay settings in the switchyard had been set appropriately, the event would have been limited to the actuation of main step-up transformer 1A differential protective relaying and the Yellow bus differential protective relaying to address the fault on the X-phase of the CT associated with PCB 18. Actuation of the main step-up transformer 2B differential protective relaying would have occurred to address the fault on the Y-phase of the CT associated with PCB 23. This would have resulted in the following breakers opening:

- Yellow bus (87BY) differential - PCB's 12, 15, 18, 21, 24, 27, 30 and 33
- Zone 1A (86A) lockout - PCB's 18 (repeat signal), 17 and GCB 1A
- Zone 2B (86B) lockout - PCB's 23, 24 (repeat signal) and GCB 2B

Both units would have runback to 48% main generator electrical output. In combination with the number of transmission lines available, the design of the switchyard should have prevented Units 1 and 2 from losing offsite power.

b.2 Integrated Plant Response:

A detailed time line of events and time/date stamps is provided in Attachment 10, "Integrated Plant Response Sequence of Events."

On 20 May 2006 at 2:01 p.m. EDT, a phase-to-ground electrical fault within the current transformer on the Catawba Unit 1 main step-up transformer 1A line position occurred within the 230kV switchyard resulting in a Loss of Offsite Power (LOOP) event for both Unit 1 and Unit 2. Both reactors tripped from 100 percent power, as expected. Control room operators entered emergency operating procedure EP/1(2)/A/5000/E-0, Reactor Trip or Safety Injection, for both units and then transitioned to emergency operating procedure EP/1(2)/A/5000/ES-0.1, Reactor Trip Response.

The first-out annunciator on Unit 1 indicated the reactor trip was caused by an "NI Hi Flux Rate Power Range" signal. Subsequent analysis of plant data determined that the actual cause of this signal was from an electrical perturbation on the instrument bus resulting from the large fault in the switchyard. It was confirmed that an actual increase in reactor power significant enough to have generated an "NI Hi Flux Rate - Power Range" signal did not occur prior to the transient and reactor trip. All other expected reactor trip signals for the conditions present were received.

The first-out annunciator on Unit 2 indicated that the reactor trip was caused by actuation of the under frequency relays associated with the reactor coolant pump electrical busses. This is an expected reactor trip signal for the condition present.

All reactor trip breakers opened as expected and all control rods fully inserted into the core on the two units.

Both main turbines tripped upon receipt of the reactor trip signals. Following the loss of all offsite electrical power, the four (4) emergency diesel generators started and supplied power to the 4.16kV vital busses. Designated vital equipment was re-energized in accordance with the plant design through the diesel generator load sequencers. Operators implemented Abnormal Operating Procedure AP/1(2)/A/5500/007; Loss of Normal Power, to respond to the electrical transient.

A NOUE was declared at 2:14 p.m. on May 20, 2006, due to the loss of AC electrical power from all offsite sources for more than 15 minutes with onsite power available. The TSC, OSC, and subsequently the EOF were all activated on a precautionary basis.

The auxiliary feedwater pumps (3 per unit) started automatically to maintain water levels in the steam generators following the loss of the main feedwater pumps. Secondary-side pressure control transitioned from the steam dumps to the steam generator power operated relief valves (PORV's) once steam generator pressure dropped below 775 psig and a main steam line isolation signal was generated. Two of the three pressurizer PORV's on Unit 1 and one of the three PORV's on Unit 2 cycled during the initial phase of the transient to maintain primary system pressure.

The Technical Specifications for several safety-related systems required both on and offsite power to be available. The loss of the offsite power sources placed both units in Technical Specification 3.0.3 necessitating a natural circulation cooldown be performed in order to be in Mode 4 within 14 hours of the initiating event. Operators entered emergency procedure EP/1(2)/A/5000/ES-0.2; Natural Circulation Cooldown; and proceeded to reduce primary pressure and temperature in accordance with the guidance contained in the procedures. Once offsite power had been re-established, the cooldown was terminated and the units stabilized at approximately 470F and 1850 psig.

Power was restored to the Unit 2 6.9kV busses at 8:27 p.m. on May 20, 2006, and to the Unit 1 6.9kV busses at 8:40 p.m. Due to lockouts on the 1A and 2B main transformers, full realignment of breakers to provide offsite power to the vital busses and securing of all four diesel generators did not occur until approximately 1:10 a.m. on May 21, 2006. The Notice of Unusual Event was terminated at 1:45 a.m. on May 21, 2006.

Reactor Coolant Pumps were started to re-establish forced circulation on Unit 1 at 3:20 p.m. on May 21, 2006. Due to biological debris fouling of the Unit 1 reactor coolant pump motor coolers, all reactor coolant pumps were secured on May 22, the unit cooled down to Mode 5 on natural circulation and the residual heat removal system placed in-service. Following resolution of all issues required for restart, Unit 1 was returned to service on June 10, 2006.

Forced circulation was re-established on Unit 2 at 11:06 a.m. on May 21, 2006 and the unit remained in Mode 3 until all issues tied to restart had been resolved. Unit 2 was returned to service on May 26, 2006.

b.3 Emergency Response Organization Response:

A detailed time line of Emergency Response Organization actions is provided in Attachment 9, "Emergency Response Organization Sequence of Events."

On May 20, 2006 at 2:01 p.m. EDT, a phase-to-ground electrical fault within the current transformer on the Catawba Unit 1 main step-up transformer 1A line position occurred within the 230kV switchyard resulting in a Loss of Offsite Power (LOOP) event for both Unit 1 and Unit 2. The Operations Shift Manager (OSM) declared a Notice of Unusual Event at 2:14 p.m. based on the existing Emergency Plan entry condition of the loss of all offsite power to essential busses for greater than 15 minutes with all emergency diesel generators supplying power to their respective 4.16kV busses.

The Control Room Offsite Agency Communicator made the required initial verbal notifications to local and State agencies. The notification to York County Emergency Management (EM) was delayed due to a problem with the selective signal system. The problem was subsequently traced to a blown fuse in York County's system. York County emergency response personnel were notified via a second phone call during which the event declaration information was read over the phone and transcribed remotely.

The first follow-up update was also made by the Control Room Offsite Agency Communicator; however, the notifications took longer than usual because the loss of non-essential power resulted in the control room fax machines being unavailable. The communicator was required to call the individual offsite agencies and read the notification message to the state and county warning point telecommunicators while that person wrote down the information on a blank notification form. The loss of the fax capabilities resulted in the follow-up update being completed within 74 minutes of the initial notification versus the expected 60 minute time period (a 4 hour requirement for follow-up notifications exists).

The OSM activated the TSC and OSC as a precautionary measure to ensure any necessary resources were readily available on-site to respond to the LOOP event. The TSC and OSC were activated at 3:50 p.m. at which time responsibility for offsite agency communications was transferred to the TSC from the Control Room Offsite Agency Communicator. During the event, the NRC Operations Center was not notified within one hour of the initial NOUE declaration as required by 10 CFR 50.72(a)(3). This oversight was identified by TSC personnel and the NRC Operations Center was notified of the event at 4:15 p.m., which was 61 minutes late. The NRC Resident Inspectors had been notified at 2:14 p.m. as part of the initial Emergency Response Organization pager call-out and had responded to the site within 30 minutes of this notification.

The EOF was activated at 6:19 p.m. at the request of the TSC Emergency Coordinator. The EOF staff provided support to the site by assuming the responsibility for offsite agency communication. Hourly updates were provided to state and local agencies, as required, by the EOF staff.

At 1:45 a.m. on May 21, 2006, after offsite power was restored to all four 4.16kV essential busses, the NOUE was terminated. The EOF, TSC, and OSC organizations were released and the Outage Control Center was staffed to support stabilization and recovery activities for both units.

Additional assessment of the timeliness of the licensee's emergency response organization response to the LOOP is required and identified as Unresolved Item (URI) 05000413, 414/2006009-01, Timeliness of Notification to the NRC of Loss of Offsite Power Event on May 20, 2006.

.2 Identify and evaluate the effectiveness of the immediate actions taken by the licensee in response to the LOOP event including the accuracy and timeliness of the licensee's classification of the event

a. Inspection Scope

The inspectors evaluated the response of the licensee's staff to the LOOP from the start of the event until the NOUE was terminated through the review of logs, completed procedures and statements, conducting interviews with Operations and Emergency Response Organization personnel, as well as actual observations of recovery activities in the control room, Operations Support Center, and Technical Support Center immediately following the event conducted by the Catawba Resident Inspectors.

b. Findings and Observations

The LOOP event started at 2:01 p.m. on Saturday, May 20, 2006. Therefore, the site was staffed at weekend levels; i.e., limited engineering, maintenance and support staff available. The on-shift crew responded to the event through actions in the control room by licensed operators and throughout the plant by non-licensed operators. Additional support was provided by all other available on-site personnel prior to the arrival of the staff called out as part of the Emergency Response Organization. A second Senior Reactor Operator (SRO) in the control room allowed an SRO to be dedicated to each unit in order to direct the actions dictated by the Emergency Operating procedures implemented following the LOOP and reactor trips. While the operators experienced some minor equipment malfunctions, the procedures in-use allowed them to respond to those issues and stabilize plant conditions on both units.

The OSM declared a NOUE at 2:14 p.m. due to the loss of all offsite power for greater than 15 minutes with onsite power available. The decision to declare a NOUE was made 2 minutes prior to meeting the actual Emergency Plan entry conditions based on the recognition that offsite power would not be imminently restored. The Emergency Response Organization was notified by pager at that time and instructed to activate the TSC and OSC on a precautionary basis. Both of these facilities were staffed and activated by 3:50 p.m. and the responsibility for communicating with offsite agencies was assumed by TSC personnel. The EOF was activated at the request of the TSC Emergency Coordinator at 6:19 p.m.

Overall, operator response to the LOOP event was deliberate and effective in stabilizing the units and restoring offsite power through the use of approved station procedures. The Emergency Response Organization responded to the event promptly. With the exception of initial NRC Operations Center notification as discussed in Section 4OA5.1.b.3, the Emergency Planning program was successfully implemented from initial declaration of the NOUE until the event was terminated following restoration of offsite power to all 4.16kV vital electrical busses.

.3 Identify additional actions planned by the licensee in response to this event, including the time line for their completion of the investigation and follow-on analysis

a. Inspection Scope

The inspectors reviewed the licensee's Trip and Transient Investigation report for each unit. An independent review of operator aid computer data, control room logs, emergency response organization logs, PIP's and work orders was performed to determine if all equipment-related issues following the loss of offsite power event were identified and properly prioritized. Discussions were held with members of the station's Failure Investigation Process (FIP) Team as well as the corporate Special Event Investigation Team (SEIT) conducting an independent review of the event.

b. Findings and Observations

The licensee developed unit-specific action item lists following the LOOP event. The lists identified actions that were either required to be completed prior to the restart of each unit or were either generic in nature or required additional time to complete and not required for restart.

The following tables contain a summary of equipment-related issues that were identified following the loss of offsite power event of May 20, 2006 and the 1A diesel generator room flooding of May 22, 2006, if they were required to be resolved prior to restart and the actions taken by the licensee to address them. Due to the extent of actions tied to the electrical plant following the LOOP, those issues are contained in a separate table.

UNIT 1 : Non-Electrical Issues			
Issue	**Details**	**Req. for Restart**	**Status**
Initial reactor trip signal was on Hi Flux Rate;	The signal was attributed to an electrical perturbation	NO	PIP C-06-3874 was initiated to conduct an Apparent Cause

UNIT 1 : Non-Electrical Issues			
Issue	**Details**	**Req. for Restart**	**Status**
however, actual conditions for this signal did not exist.	caused by the power range NI grounding system. This response was seen on a previous LOOP at Catawba 1		assessment into the cause of the signal. (PIP C-06-3874)
Loop B hot leg RTD card failed several minutes into the event	The cards required replacement and calibration.	YES	The cards were replaced and recalibrated. (WO 98790462 / PIP C-06-3879)
Excess letdown control valve 1NV-122 would not open following the reactor trip	The valve was repaired and stroked successfully.	YES	Repairs were completed (PIP C-06-3873)
Normal letdown variable orifice control valve failed to re-open following event	The valve has been repaired and stroked successfully.	YES	Repairs have been completed (WR 98375944)
1D steam generator PORV was slow to open	The positioner required recalibration	YES	Repairs were completed. (PIP C-06-3883)
Unsealed electrical conduits resulted in flooding of the 1A DG room	Conduits between the cooling tower cable trench and RN conduit manhole CMH-04A were not sealed per design drawings. Conduits between CMH-3 and the 1A DG room were not sealed per design drawings.	YES	All penetrations into the Unit 1 A and B diesel generator rooms were sealed per construction drawings. (PIP C-06-3902)
"A" Control Area chilled water chiller failed to auto start following the event	A loose wire on the Program Timer within the chiller control panel was found.	YES	Wiring was reterminated. (WO 98791173 / PIP C-06-4037)

UNIT 1 : Non-Electrical Issues			
Issue	**Details**	**Req. for Restart**	**Status**
Motor stator coolers for the reactor coolant pumps and the LCVU coolers exhibited restricted flow following the event	On a loss of offsite power the normal cooling source (YV) swapped to the backup source (RN). Debris in no-flow sections on the RN piping was flushed into the motor stator coolers and LCVU coolers requiring disassembly and cleaning.	YES	All 4 reactor coolant pump motor stator coolers and LCVU coolers were cleaned. (PIP C-06-3935)
1A1 and 1A2 WN sump pumps in the 1A DG room failed following being submerged after conduit flooding event	The two sump pumps were totally submerged after the 1A DG room flooded. The motors required replacement.	NO	The motors were replaced and tested. (WO 98791331)

UNIT 2 : Non-Electrical Issues			
Issue	**Actions**	**Req. for Restart**	**Status**
Digital Feedwater Control System driver card for the 2B CFPT failed and switched to the backup card	The primary card needs to be replaced and functional test performed.	NO	Primary card has been replaced and calibrated. (PIP C-06-3897)
Zone B lockout occurred following the reactor trip	The Y Phase current transformer associated with PCB 23, and specifically the secondary winding utilized in the Zone 2B differential protection circuit actuated during the LOOP, was found to be damaged during a current transformer saturation test.	NO	The current transformer for PCB 23 Y Phase was replaced with a new unit that was stored in the CNS Switchyard (PIP C-06-4089)

UNIT 2 : Non-Electrical Issues			
Issue	**Actions**	**Req. for Restart**	**Status**
DRPI indication for rods H4 and D8 did not go to zero following the reactor trip	Subsequent review determined that the indication was for the OAC only.	NO	Problem found on a digital input card in the OAC. Card was reset and indication problems cleared. (PIP C-06-3881)
Tavg indication drifted high following the reactor trip	Tavg NSA card determined to require recalibration	YES	Recalibration performed prior to restart. (PIP C-06-3991)
VCT relief valve failed to open at its 75 psig setpoint	The VCT pressure reached 92 psig during the event. An analysis was performed to assess the structural integrity impact due to this pressure transient.	YES	Analysis showed that the integrity of the tank and piping was not adversely affected. No replacement of the valve was planned. (PIP C-06-3927)
"A" Control Area chilled water chiller failed to auto start following the event	A loose wire on the Program Timer within the chiller control panel was found.	YES	Wiring has been reterminated. (WO 98791173 / PIP C-06-4037)

Station Electrical Issues			
Issue	**Actions**	**Req. for Restart**	**Status**
Due to the electrical fault, possible damage may have occurred to the CT's on PCB's 17 & 18	Perform Doble and/or Saturation testing on X, Y, and Z phases of PCB's 17 and 18	YES	All 3 phases of PCB 17 and 18 were Doble tested; however, Saturation testing was not found to be required on PCB 17. WO 9879052 WO 9879053 WO 9879054
The CT on the X phase of PCB 18 failed, initiating the LOOP event	Replace the X-phase CT on PCB 18 and any other damaged components	YES	The CT and associated wiring / conduits were replaced. WO 98790418
Based on OE from MNS, the potential for degradation of the MOD contacts following a fault on the transmission line existed	Visually inspect the disconnects associated with PCB 17's and 18	YES	Visual inspections completed and no repairs required. WO 98790594 WO 98790593 WO 98790581 WO 98790580
Inspect PCB's 17 and 18 for damage or excessive build-up of arc extingushment "salt"	Perform Doble testing and visual inspections of the PCB's	YES	Doble testing performed satisfactorily, cleaned arcing contacts and replaced main contacts. WO 98790416 WO 98790417

Station Electrical Issues			
Issue	**Actions**	**Req. for Restart**	**Status**
Zone 2B Protective Relays need to be tested to verify calibration following the LOOP	Relay calibrations were required and visual inspections of connections were performed to ensure no degradation exists	YES	All relays were found to be satisfactory in the "as-found" condition. No other repairs were required. WO 98790852
Differential relays were not set in IAW Power Delivery requirements	Verify current differential relays on the Red and Yellow busses and adjust as required to meet Power Delivery requirements	YES	The 87BY X-Y-Z (Yellow bus) and 87BR X-Y-Z (Red bus) differential relays were checked and reset as required. WO 98790851 WO 98790853 WO 98790443
Determine why the 2B Zone Lockout occurred	Based on Engineering recommendations, several tests were performed on the 2B transformer	YES	After disconnecting the high and low side of the transformer, the post-trip Doble test was completed satisfactorily. The transformer was demagnetized as the excitation results were not within the normal range. All tests were Satisfactory at the completion. WO 98790412 WO 98790413 WO 98790414 WO 98790415
Ensure there is no issue related to the 1A transformer following the LOOP event	Perform post-trip Doble testing to ensure no problems exist following differential actuation	YES	Testing indicated that there were no problems with the 1A transformer WO 98790430

Station Electrical Issues			
Issue	**Actions**	**Req. for Restart**	**Status**
The MOD was not opened within 1 hour of the individual PCB's opening which may have resulted in the degradation of grading capacitors in the interrupter heads.	Perform post-trip Doble tests on individual PCB's to ensure no degradation occurred. PCB's 14, 17, 18, 20, 23, and 24 were tested.	YES	Doble testing completed satisfactorily WO 98790433 WO 98790434 WO 98790435 WO 98790436 WO 98790437 WO 98790438
Investigate the cause of the PCB 18 CT failure.	Gas concentration of several PCB's scheduled to be checked based on past history and issues related to moisture intrusion into CT's. PCB's to be checked include PCB 14, 15, 17, 18, 20, 21, 23 and 24	NO	Testing was in progress, no issues found to-date. WO 98790585 WO 98790586 WO 98790587 WO 98790588 WO 98790589 WO 98790590 WO 98790591 WO 98790592
Copper splatter was found on the neutral bushing of the 2B Main S/U transformer due to the fault current	The neutral bushing required cleaning following experiencing the high fault current associated with the event	YES	The bushing was cleaned WO 98791075
During the investigation into the Unit 2 2B lockout, Power Delivery recommended that testing be conducted	The CT's for the X, Y and Z phases on PCB's 23 and 24 were isolated and tested to check for damage	YES	All 3 CT's on PCB 24 tested satisfactorily. The Y phase CT on PCB 23 failed and was replaced. No other problems were identified. WO 98791140 WO 98791142

.4 <u>Assess the circumstances surrounding the multiple lifting and reseating of the Unit 1 and Unit 2 primary power operated relief valves (PORVs)</u>

a. Inspection Scope

Inspectors assessed the circumstances surrounding the multiple lifting and reseating of the Unit 1 and Unit 2 pressurizer PORVs to determine if the PORVs responded appropriately during the event. System Engineering personnel were interviewed and design documents and calibration procedures were reviewed to support this assessment.

b. Findings and Observations

Each unit is equipped with three pressurizer PORVs. The PORVs are air operated valves each having a relief capacity of 210,000 lbm/hr at a nominal lift setpoint of 2,335 psig. The PORVs are designed to maintain primary plant pressure below the pressurizer pressure high reactor trip setpoint of 2,385 psig following a step reduction of 50% of full load with steam dump operation. The PORVs minimize challenges to the pressurizer safety valves and may also be used for low temperature over pressure protection (LTOP). The PORVs and their associated block valves may also be used by plant operators to depressurize the reactor coolant system (RCS) to recover from certain transients if normal pressurizer spray is not available.

During a LOOP, normal pressurizer spray is not available due to a loss of all reactor coolant pumps. Primary system pressure control is then automatically provided via the PORVs and the pressurizer pressure master controller. The pressurizer pressure master controller is a "proportional plus integral" (P-I) controller with a nominal PORV setpoint designated as P_{ref} of 2,235 psig. As primary system pressure increases during a LOOP event, the pressurizer pressure master controller will cycle one PORV (NC-34A) over a 20 psig band to return RCS pressure to a nominal P_{ref} setpoint of 2,235 psig. The other two PORV's will lift when pressure reaches their respective lift setpoints.

Specific to the May 20, 2006 LOOP event, Unit 1 PORVs 1NC-32B and 1NC-34A actuated appropriately. 1NC-34A cycled in automatic a total of 57 times as the P-I controller attempted to return RCS pressure to the 2,235 psig P_{ref} setpoint. PORV 1NC-32B cycled a total of five times as RCS pressure exceeded its 2,335 psig lift setpoint. The Unit 2 PORV, 2NC-34A automatically cycled a total of 35 times as the P-I controller attempted to return RCS pressure to the 2,235 psig P_{ref} setpoint. The total number of cycles differs between the units due to Unit 1's higher initial pressurizer level and subsequent higher pressurizer pressure and the associated recovery time required to re-establish normal RCS letdown flow. Graphs showing the pressurizer pressure versus time following the LOOP for both units which demonstrate how the PORV's were operating to return pressure to the P_{ref} setpoint are provided as Attachment 7.

A comparison of the May 20, 2006 plant response to historical data obtained from a 1996 Unit 2 LOOP event was conducted. This review revealed similar and consistent PORV cycling to maintain RCS pressure for the similar event.

In summary, the PORVs on both units operated as designed to control primary plant pressure.

.5 Determine if there are any generic issues related to this event which warrant an additional NRC response. As part of this review, assess the implications of a common cause failure of the emergency diesel generators due to external flooding. Promptly communicate any potential generic issues to regional management.

a. Inspection Scope

During the inspection team's investigation into the event; equipment issues, procedures, and design documents were reviewed to determine if there were any generic issues that required additional review by NRC personnel. In addition, the partial flooding of the 1A diesel generator room that occurred on May 22, 2006 was also reviewed by the team for generic implications.

The inspectors reviewed unified control room logs, operator aid and process computer alarm logs, sequence of event recorder reports, emergency response organization logs from the TSC, OSC and EOF, statements from individuals involved in the event and timelines developed by licensee personnel. The inspectors also interviewed licensee personnel to validate and clarify the sequence of events which occurred on May 20, 2006. Notes generated by the Resident Inspectors who responded to the event and were in the control room, OSC, and TSC until the NOUE was terminated were also reviewed. To identify potential generic implications of the events, the Final Safety Analysis Report (FSAR), design basis documents, Catawba calculations, relay setpoint sheets from the Power Delivery Department, 10 CFR 50 Appendix A, "General Design Criteria", and corrective action program documents were reviewed by the inspection team members.

b.1 Switchyard Design and Relay Settings

The inspectors reviewed the design of the offsite power system for compliance with the requirements of 10 CFR 50, Appendix A, General Design Criterion 17. This criterion requires two physically independent circuits from the transmission network to the onsite electrical distribution system, with one of these circuits being available within a few seconds following a loss-of-coolant accident to ensure that core cooling, containment integrity, and other vital safety functions are maintained. The team found no regulatory issues with the overall as-designed switchyard configuration nor theory of operation.

However, the Red bus differential relay actuation, resulting in opening of all the 230 KV switchyard Red bus tie-breakers was apparently caused by incorrect setting of the relays. This issue remains unresolved pending further inspection to review the root and contributing causes, the extent of condition, and the corrective actions, specifically the latent presence of inappropriate setpoints in the bus differential relaying associated with the Red and Yellow buses. It is identified as URI 05000413, 414/2006009-02, Improper relay settings in the Catawba 230kV switchyard resulted in a total loss of offsite power following failure of a PCB current transformer.

The licensee determined that the differential relays had not been set in accordance with the relay setpoint calculations developed in 1981 by Duke Energy's Power Delivery Department. The setpoints had been developed in 1981, which was prior to commercial operation of either Catawba unit and the establishment of site System Engineering.

b.2 Description of 1A Diesel Generator Room Flooding Event

On May 22, 2006, the control room was notified of water flooding into the 1A DG room. Operators were dispatched and identified that the flooding was coming in through below-grade electrical conduits on the south wall. The source of the water was determined to be overflow from the Unit 2 cooling towers, through the cooling tower cable trench, into two safety-related manholes and finally into the 1A DG room. Once the cooling towers had been secured, the in-leakage stopped. The conduits into the manholes and the 1A DG room were found not to be sealed as required per design and construction documents.

The water flowed over the starting air compressors, DG battery enclosure, and load sequencer cabinets, and collected in the DG sump. The rate of flooding exceeded the capacity of the installed DG sump pumps. Additional sump pumps had to be brought in to keep the water from reaching the lube oil sump tank and the generator. Neither of these components were wetted.

The 1A DG was declared inoperable and the applicable Technical Specifications were entered. An operability assessment and several additional inspections were required to be performed prior to declaring the diesel generator operable. In addition, the electrical conduits entering manhole CMH-4A from the cooling tower cable trench and those entering the 1A DG room from manhole CMH-3 were sealed in accordance with design drawings.

Inspections were performed on all other electrical conduits that entered the auxiliary building through below-grade penetrations to ensure they were properly sealed. Approximately 45 electrical conduits required repairs of the moisture seals to restore them to their as-built design condition.

The team identified Unresolved Item 05000413/2006009-03 to review the root and contributing causes, the extent of condition, and the corrective actions associated with the failure to seal conduits into manholes and the 1A DG room as required by design and construction documents.

The team also identified Unresolved Item 05000413, 414/2006009-04 to review the extent of condition and corrective actions taken to address degraded seals found on below-grade electrical conduits entering areas of the auxiliary building containing safety-related equipment.

4OA6 Meetings

Exit Meeting Summary

On May 26, 2006, the inspection team presented the preliminary inspection results to Mr. Jamil and members of his staff of the Augmented Inspection in progress. On May 31, 2006, the Region II Director, Division of Reactor Projects, the Augmented Inspection Team Leader and the Catawba Senior Resident Inspector presented the results of the inspection in a public meeting at the Rock Hill City Hall to Mr. Jamil and other members of his staff. Mr. Jamil acknowledged the findings and observations of the team at that time. All proprietary information reviewed by the team was returned to the licensee.

ATTACHMENT - SUPPLEMENTAL INFORMATION

1. Key Points of Contact
2. List of Items Opened, Closed and Discussed
3. List of Documents Reviewed
4. List of Acronyms
5. Augmented Inspection Team Charter
6. Catawba Main Generator, Transformers, and 230kV Switchyard Simplified Diagram
7. Unit 1 and Unit 2 Pressurizer Pressure Traces
8. Electrical Plant Sequence of Events
9. Emergency Response Organization Sequence of Events
10. Integrated Plant Response Sequence of Events

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

E. Beadle, Emergency Planning Manager
G. Black, Civil System Engineer
J. Caldwell, I&C / Electrical Maintenance Manager
K. Caldwell, Electrical System Engineer
T. Daniels, Emergency Planning
A. Dickard, Senior Engineer, Electrical Systems
A. Dubois, Power Deliver Services (PDS)
J. Ferguson, Safety Assurance Manager,
R. Freudenberger, EIT Leader
G. Hamrick, Mechanical / Civil Engineering Manager
R. Hart, Regulatory Compliance
J. Herrington, Senior Engineer, Primary Systems
W. Hogan, Fire Protection Engineer, MCE
D. Jamil, Site Vice President
K. Lyle, FIP Team Leader
S. Mays, Reactor Coolant System Engineer
G. Mitchell, Emergency Planning
V. Paterson, Public Relations
M. Patrick, Work Control Superintendent
T Pitesa, Station Manager
T. Ray, Maintenance Superintendent
R. Repko, Engineering Manager
R. Smith, Emergency Planning
G. Strickland, Regulatory Compliance Specialist
K. Thomas, Corporate Manager, Regulatory Compliance, SEIT Leader
C. Trezise, Operations Superintendent
T. Wingo, System Engineer

NRC

C. Casto, Director DRP, Region II
C. Payne, Acting Branch Chief, Region II, Branch 1
J. Stang, Project Manager, NRR
W. Travers, Region II Regional Administrator
W. Rogers, RII Senior Reactor Analyst

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000413, 414/2006009-01	URI	Timeliness of Notification to the NRC of Loss of Offsite Power Event on May 20, 2006.(Section 4OA5.1.b.3)
05000413, 414/2006009-02	URI	Improper relay settings in the Catawba 230kV switchyard resulted in a total loss of offsite power following failure of a PCB current transformer (Section 4OA5.5.b.1)
05000413/2006009-03	URI	Review of failure to seal conduits into manholes and the 1A DG room as required by design and construction documents (Section 4OA5.5.b.2)
05000413, 414/2006009-04	URI	Review the extent of condition and corrective actions to address degraded seals on below-grade electrical conduits entering the auxiliary building (Section 4OA5.5.b.2)

LIST OF DOCUMENTS REVIEWED

Technical Specifications

Catawba Nuclear Station UFSAR Chapter 5
Catawba Nuclear Station Technical Specifications 3.4, 3.5, 3.8
Catawba Nuclear Station Technical Specification Bases 3.4, 3.5, 3.8

Calculations / Specifications

CNS-1465.00-00-0021, Design Basis Specification for the Plant and Offsite Power Protective Relaying, Rev. 0
CNS-1553.NC-00-0001, Design Basis Specification for the Reactor Coolant (NC) System, Rev. 25
CNS-1465.00-00-0005, Design Basis Specification for the Design Basis Event, Rev. 2
CNC-1223.12-00-0051, Effect of PORV Operation on CLA Nitrogen Pressure and NI System Operability Calculation

Drawings

CN-1938-01; Electrical Equipment Layout; Outdoor Area; General Plan
CN-1938-04, 05, 06 and 07; Electrical Equipment Layout; Outdoor Area; Section and Details

Procedures / Surveillances

EP/1/A/5000/E-0; Reactor Trip or Safety Injection; Rev. 27
EP/1/A/5000/ES-0.1; Reactor Trip Response, Rev. 22
EP/1/A/5000/ES-0.2; Natural Circulation Cooldown, Rev. 19
AP/1/A/5500/007; Loss of Normal Power; Rev. 49
AP/1/A/5500/012; Loss of Charging or Letdown; Rev. 23
EP/2/A/5000/E-0; Reactor Trip or Safety Injection; Rev. 26
EP/2/A/5000/ES-0.1; Reactor Trip Response, Rev. 22
EP/2/A/5000/FR-1.1; Response to High Pressurizer Level, Rev. 11
AP/2/A/5500/012; Loss of Charging or Letdown; Rev. 19
AP/2/A/5500/007; Loss of Normal Power; Rev. 49
PT/0/A/4150/002A; Transient Investigation; Rev. 0 (For Unit 1 and Unit 2)
IP/0/B/3112/008; Calibration of RN System Conduit Manhole Sump Level Switches, Rev. 004
IP/0/A/3850/013B; Procedure for Sealing Rigid Steel Field Run Conduit; Rev. 10
EP/1/A/5000/E-0; Reactor Trip or Safety Injection, Rev. 027
IP/1/B/3222/063; Calibration Procedure for Pressurizer Pressure Control, Rev. 027

Miscellaneous Documents

Dow Corning 732 Multi-Purpose Sealant Product Data Sheet
NSD-407, Maintenance Interface Agreement for Nuclear Generation, Electric Transmission, Information Management, and Power Generation Departments, Rev. 06
NSD-409, Engineering Guidlines for Nuclear Station Switchyard and Main Step-Up Transformer Activities, Rev. 06
NSD-502, Corporate Conduct of Operations in the Switchyard, Rev. 07

Work Orders

WO 98791331; 1A1 and 1A2 WN sump pumps failed meggar testing following submergence when water drained from manhole CMH-3 into the 1A diesel generator room.
WO 98790811; 2B Digital Feedwater Control System primary driver card failed and swapped to the backup card.
WO 98766406; Remove hatches and inspect manholes CMH-18A and B
WO 9879087; Seal conduits in CMH-18A
WO 9879098; Seal conduits in CMH-18B

Work Orders associated with the switchyard and main generator activities
WO 9879052
WO 9879053
WO 9879054
WO 98790418
WO 98790594
WO 98790593
WO 98790581
WO 98790580
WO 98790416
WO 98790417
WO 98790852
WO 98790851
WO 98790853
WO 98790443
WO 98790412
WO 98790413
WO 98790414
WO 98790415
WO 98790430
WO 98790433
WO 98790434
WO 98790435
WO 98790436

WO 98790437
WO 98790438
WO 98790585
WO 98790586
WO 98790587
WO 98790588
WO 98790589
WO 98790590
WO 98790591
WO 98790592
WO 98791075
WO 98791140
WO 98791142

PIPs

PIP C-06-4180, Need to incorporate the pressurizer PORV operation into future training and Operating Experience
PIP C-06-4150, PORC meeting held on 5/29/06 for the restart of Unit 1
PIP C-06-4149, Operability assessment for the conduit between manholes CMH-2, 3, 18A and 18B and their respective diesel rooms due to the conduit now being sealed on both ends.
PIP C-06-4112, Questions / concerns raised over the inspections performed on conduit seals in manholes CMH-18A&B which required rework
PIP C-06-4106, Critique of the Trip and Transient process following the LOOP
PIP C-06-4089, Y Phase Current Transformer associated with PCB 23 found to be damaged.
PIP C-06-4087, Resident Inspector identified that spare conduits were to be stubbed out and capped per the drawing. Conduit was sealed instead. Need to resolve difference.
PIP C-06-4049, Action items from the PORC meeting held on 5/24/06 to discuss the cause(s) of the Unit 1 and Unit 1 LOOP event
PIP C-06-4037, PORC action items from plant transient investigation into the Unit 2 reactor trip following the LOOP on 5/20/06
PIP C-06-4012, E1 work request written to inspect cooling tower trenches for water barrier integrity
PIP C-06-4007, E1 wqork request written to inspect and seal conduit sleeves for CMH-16B
PIP C-06-3983, E1 work requests written to inspect essential cabinets for water intrusion after 1A diesel generator flooding
PIP C-06-3947, E1 work request issued to repair the 1A DG prelube pump which will not start
PIP C-06-3941, Power Delivery questioned the testing methods used at Catawba for transformer saturation testing
PIIP C-06-3934, Need to assess the flooding design basis for the RN conduit penetrations into the diesel generator rooms

PIP C-06-3902, Unit 2 cooling towers overflowed causing water intrusion into the 1A diesel generator room

PIP C-06-3893, Cooling towers overflowing excessively causing water to build up on the ground surrounding the towers
PIP C-06-3889, Reactor Engineering review of dual unit LOOP
PIP C-06-3886, Unit 2 containment walkdown inspection results
PIP C-06-3883, Steam Generator 1D PORV was slow to respond
PIP C-06-3874, Unit 1 reactor trip investigation following loss of offsite power
PIP C-03-3297, During the flush of 1B NS heat exchanger, the sump pump for the RN conduit manhole CMH-4A started pumping down
PIP C-03-2716, Inspection of structural components in site RN conduit manholes
PIP C-01-3842, Documentation of entries into RN conduit manholes
PIP C-06-3864, Unit 1 Loss of Offsite Power
PIP C-06-3865, Unit 2 Loss of Offsite Power
PIP C-06-3873, 1NV-122B (Excess letdown isolation) failed to open
PIP C-06-3880, 2NC-34A opened at lower pressure than setpoint during LOOP event
PIP C-06-3927, Unit 2 VCT Relief Valve (2NV223) did not function properly during dual unit Loss of Offsite Power event on 5/20/06
PIP C-06-4091, During the recent duel unit LOOP event, there was a similar drop in pressure of 17 psig in NI CLA 1A and 18 psig in NI CLA 2A. On both units, CLA pressure decreased after aligning N2 supply to the PZR PORVs 1(2)NC-34A. As identified below, the number of PZR PORV cycles for each unit 1 and 2 PZR PORV was incorrectly reported as 107 strokes and 35 strokes, respectively. This led the NRC to question reliable operation of unit 2 PZR PORV, 2NC-34A (due to similar N2 usage for significantly fewer cycles).
PIP C-96-0306, Pressurizer PORV Issues during Unit 2 LOOP
PIP C-95-1400, Calculation review identified potential grid/unit stability concerns. Analysis will be done to address these concerns
PIP C-01-1556, This PIP is to document an evaluation that has been initiated to determine if any elective NSM's should be originated for generator protection in the event of a three phase fault to ground, within ½ mile of CNS, in conjunction with a breaker failure to trip. This was previously identified in PIP C-95-01400

LIST OF ACRONYMS

AC	Alternating Current
AIT	Augmented Inspection Team
AP	Abnormal Operating Procedure
CFPT	Main Feedwater Pump Turbine
CFR	Code of Federal Regulations
CLA	Cold Leg Accumulator
CMH	Conduit Manhole
DFCS	Digital Feedwater Control System
DG	Emergency Diesel Generator
DRPI	Digital Rod Position Indication
EIT	Event Investigation Team
EM	Emergency Management (off-site agencies)
EOF	Emergency Operations Facility
EP	Emergency Operating Procedure
ERO	Emergency Response Organization
FIP	Failure Investigation Process
FSAR	Final Safety Analysis Report
GCB	Generator Circuit Breaker
GDC	General Design Criteria
KV	Kilovolt
LCVU	Lower Containment Ventilation Unit
LOOP	Loss of Offsite Power
NCV	Non-Cited Violation
ND	Residual Heat Removal System
NOUE	Notice of Unusual Event
NRC	Nuclear Regulatory Commission
NV	Chemical Volume and Control System
OAC	Operator Aid Computer
OP	Normal Operating Procedure
OSC	Operations Support Center
OSM	Operations Shift Manager
PCB	Power Circuit Breaker
PIP	Problem Investigation Process (report)
PORV	Power Operated Relief Valve
RN	Nuclear Service Water System
RTD	Resistance Temperature Detector
SDP	Significance Determination Process
SEIT	Special Event Investigation Team
SOE	Sequence of Event Recorder
TSAIL	Technical Specification Action Item Log
TSC	Technical Support Center
URI	Unresolved Item
VCT	Volume Control Tank
WN	Emergency Diesel Room Sump Pump System

WO	Work Order
WR	Work Request
YC	Control Room Chilled Water System
YV	Containment Chilled Water System

May 25, 2006

MEMORANDUM TO: James H. Moorman, Chief
Operations Branch
Division of Reactor Safety

FROM: William D. Travers, Regional Administrator ***/RA/***

SUBJECT: REVISED AUGMENTED INSPECTION TEAM CHARTER

An Augmented Inspection Team (AIT) was established on May 23, 2006, for Catawba Nuclear Station to inspect and assess the facts surrounding a loss of offsite power (LOSP) and subsequent dual unit reactor trip at Catawba on or around May 20, 2006.

The team composition and the objectives of the inspection are unchanged. However, the enclosed charter has been revised to clarify and expand on the actions to be accomplished by Item "e" to assess the implications of a common cause failure of the emergency diesel generators due to external flooding.

For the period during which you are leading this inspection and documenting the results, you will report directly to me. The guidance in Inspection Procedure 93800, "Augmented Inspection Team," and Management Directive 8.3, "NRC Incident Investigation Program," applies to your inspection.

If you have any questions regarding the objectives of the enclosed revised charter, contact Charles A. Casto at (404) 562-4500.

Enclosure: AIT Charter

Docket Nos.: 50-413 and 50-414
License Nos.: NPF-35 and NPF-52

Distribution:

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V. McCree, RII

Attachment 5

REVISED AUGMENTED INSPECTION TEAM (AIT) CHARTER
CATAWBA LOSS OF OFFSITE POWER AND DUAL UNIT REACTOR TRIP

Basis for the Formation of the AIT - On May 20, 2006, an electrical fault occurred apparently causing several power circuit breakers (PCB's) to open in the Catawba switchyard. This fault apparently caused several other PCB's to open resulting in a loss of offsite power (LOSP) and trip of both Catawba reactors. In accordance with Management Directive (MD) 8.3, "NRC Incident Investigation Program," deterministic and conditional risk criteria were used to evaluate the level of NRC response for this operational event. The review concluded that the circumstances of the event met the MD 8.3 deterministic criteria due to an apparent single electrical failure causing a loss of offsite power to both operating units and reactor trips. The risk review indicated the CCDP for the event met the criterion for an Augmented Inspection. Subsequently, Region II determined that the appropriate level of NRC response was the conduct of an Augmented Inspection.

This Augmented Inspection is chartered to identify the circumstances surrounding this event and review the licensee's actions following discovery of the conditions.

Objectives of the AIT - The objectives of the inspection are to: (1) review the facts surrounding the LOSP on May 20, 2006, and related plant complications; (2) assess the licensee's response and investigation of the event; (3) identify any generic issues associated with the event; and (4) conduct an independent extent of condition review.

To accomplish these objectives, the following will be performed:

a. Develop a complete sequence of events, including applicable management decision points, from the time the LOOP occurred until both units were stabilized.

b. Identify and evaluate the effectiveness of the immediate actions taken by the licensee in response to this event including the accuracy and timeliness of the licensee's classification of the event.

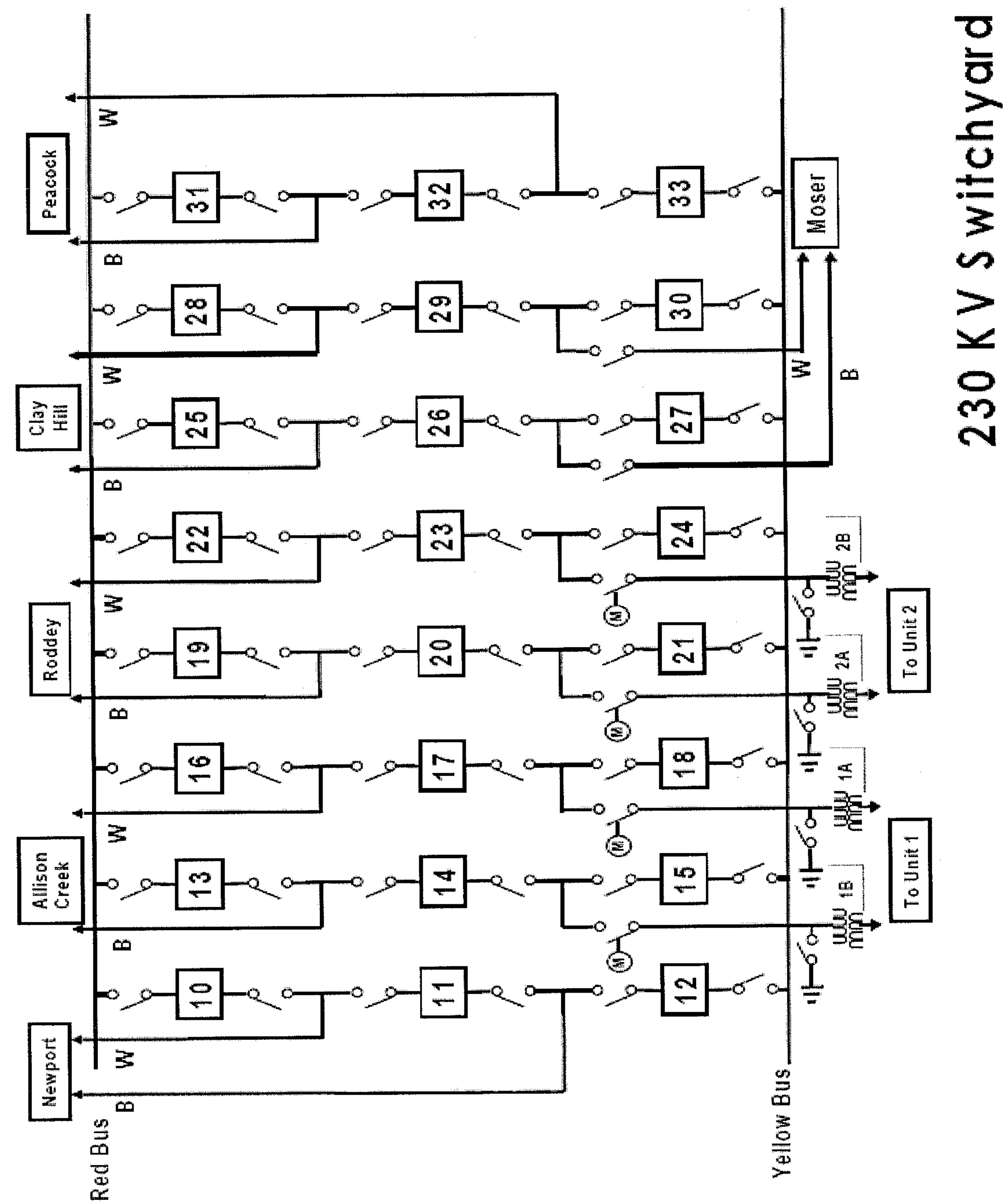
c. Identify additional actions planned by the licensee in response to this evnet, including the time line for their completion of the investigation and follow-on analysis.

d. Assess the circumstances surrounding the multiple lifting and reseating of the Unit 1 and Unit 2 primary power operated relief valves.

e. Determine if there are any generic issues related to this event which warrant an additional NRC response. As part of this review, assess the implications of a common cause failure of the emergency diesel generators due to external flooding. Promptly communicate any potential generic issues to regional management.

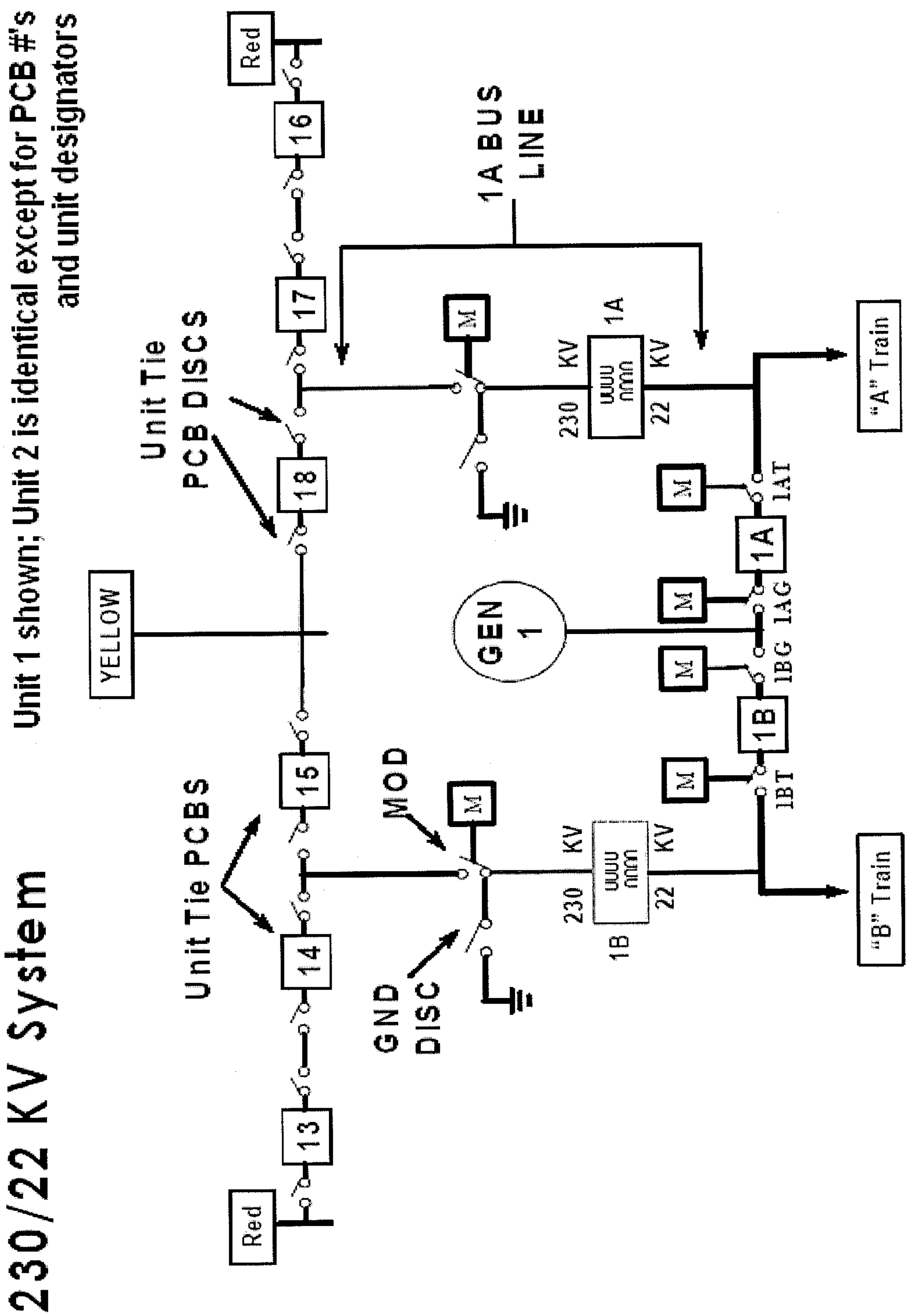
f. Document the inspection findings and conclusions in an inspection report within 30 days of the inspection.

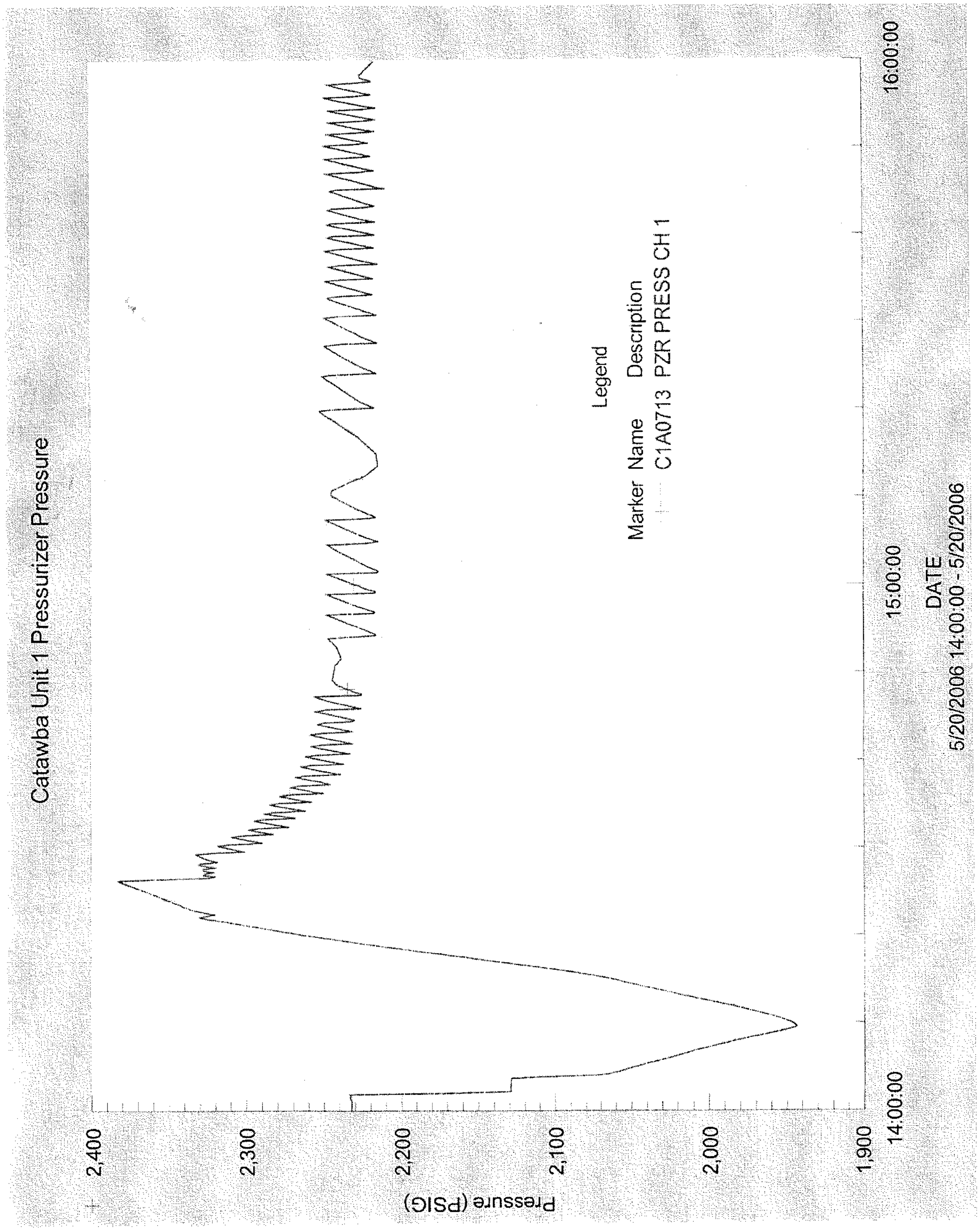
CATAWBA HIGH VOLTAGE SWITCHYARD SIMPLIFIED DIAGRAM



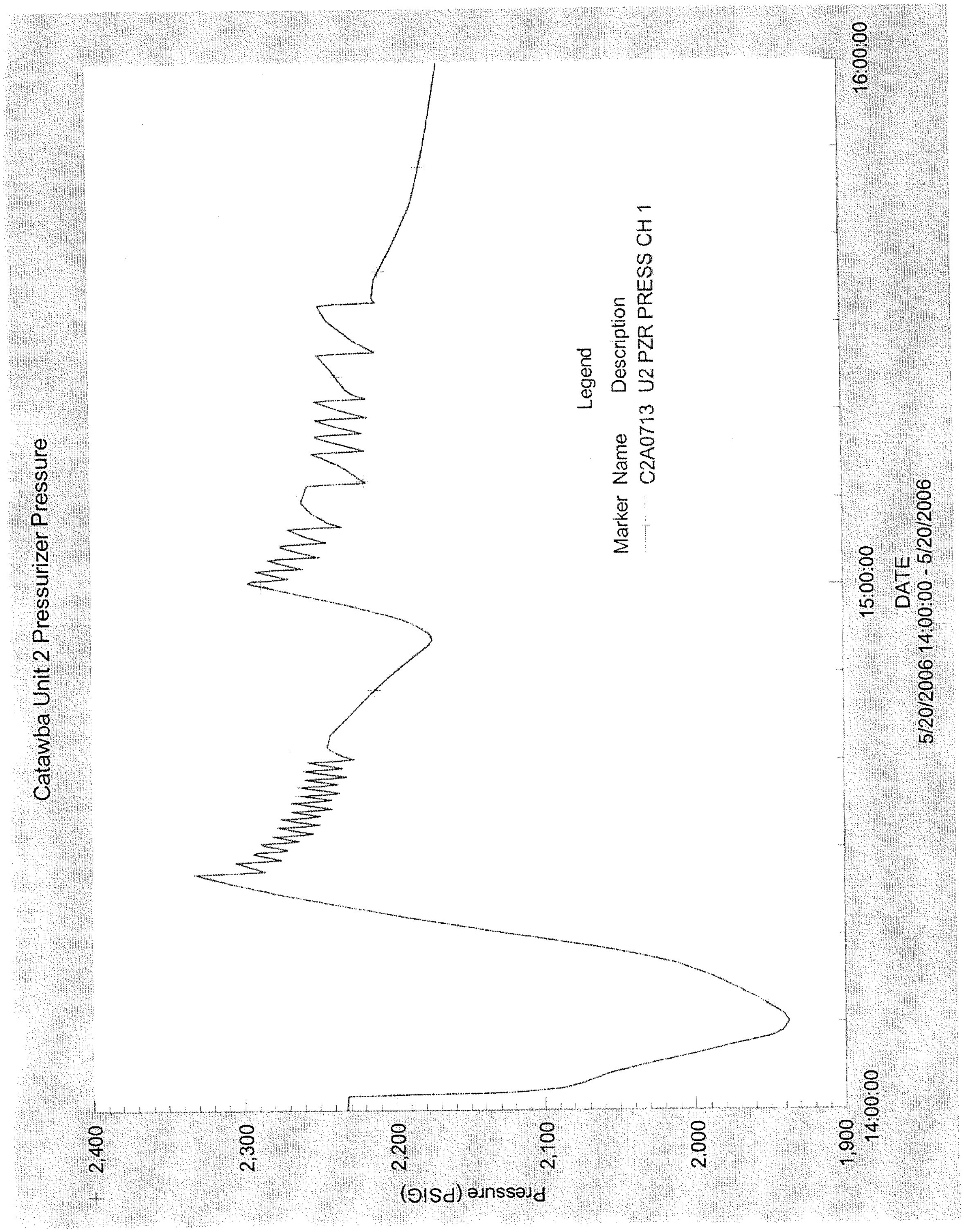
Wit
h both units at 100% power, all of the breakers shown in the simplified diagram above are in the CLOSED position.

CATAWBA MAIN GENERATOR / SWITCHYARD SIMPLIFIED DIAGRAM





Attachment 7



Attachment 7

ELECTRICAL PLANT SEQUENCE OF EVENTS

Unit	Time	Seconds from Event Initiation	Event
1	14:01:45.448	0.000	Fault occurs on the X-phase Current Transformer (CT) of Power Circuit Breaker (PCB) 18
1	14:01:45.465	0.017	Unit 1 Zone A protective lockout actuates (due to transformer 1A differential) to trip PCB's 17 and 18 and Generator Circuit Breaker (GCB) 1A
			Differential protective relaying actuates to clear the Red and Yellow busses (PCB 12 operation in response cannot be confirmed)
2	14:01:45.491	0.043	Unit 2 Zone B protective lockout actuates (due to transformer 2B differential) to trip PCB's 23, 24 and GCB 2B
2	14:01:46.068	0.620	Line distance relaying on the Roddey transmission line actuates to trip the remote line breaker and PCB 20, serving to isolate Unit 2 from all offsite power
2	14:01:45.510	1.062	Unit 2 reactor trip occurs due to underfrequency conditions on the reactor coolant pump electrical busses. The reactor protection system (RPS) generates a P4 protection signal which trips the main turbine
2	14:01:46.553	1.105	Unit 2 GCB 2B is tripped by the sequential protective tripping logic. Vital 4.16kV bus 2ETB loses power and activates the blackout logic which sends a start signal to the 2B diesel generator
1	14:01:48.172	2.724	Overcurrent conditions at the Newport Tie Station actuate a remote breaker trip, serving to isolate Unit 1 from all offsite power
1	14:01:49.394	3.946	Unit 1 reactor trip occurs due to receipt of a "NI Hi Flux Rate - Power Range" signal. The cause of this signal has been attributed to an electrical perturbation on the instrument bus resulting from the large fault in the switchyard and not from an actual change in reactor power significant enough to have produced a valid flux rate trip signal.

ELECTRICAL PLANT SEQUENCE OF EVENTS (continued)

Unit	Time	Seconds from Event Initiation	Event
1 / 2	14:01:49.581	4.133	The RPS generates a P4 protection signal which trips the main turbine. Vital 4.16kV busses 1ETA, 1ETB and 2ETA lose power and the blackout logic is activated which sends a start signal to the respective diesel generators
2	14:01:55.610	10.162	The 2B diesel generator receives a start signal and begins to come up to speed in preparation for re-energizing the vital busses
1	14:02:04.094	18.646	Bus underfrequency conditions result in relay actuation to trip PCB 14
1	14:02:04.610	19.162	Unit 1 GCB 1A is tripped by the sequential protective tripping logic
1	14:02:04.610	19.162	The 1A and 1B diesel generators receive start signals and begin to come up to speed in preparation for re-energizing the vital busses
2	14:02:13.820	28.372	The 2A diesel generator receives a start signal and begins to come up to speed in preparation for re-energizing the vital busses
1 / 2			The load sequencers on all four (4) diesel generators initiate per design to energize the necessary blackout loads in the prescribed sequence ensuring the diesel generators are not overloaded. Under the blackout loading, Load Groups 1, 2, 3, 6, 7, 8, 9, 10, 11 and 12 are automatically re-energized by the diesel generators. Equipment in Load Group 13 is given a manual start permissive 11 minutes and 50 seconds following sequencer initiation.
1/2			All blackout loads are successfully re-energized via the diesel generators.

EMERGENCY RESPONSE ORGANIZATION SEQUENCE OF EVENTS

The following table provides a summary of the actions taken by the Catawba Emergency Response Organization following the LOOP event of May 20, 2006.

May 20, 2006

TIME	COMMENT	DESCRIPTION
1401	Event Starts	Fault in the 230kV switchyard results in the loss of offsite power to both Catawba units and dual reactor trips from 100% power. All four emergency diesel generators start and re-energize the 4.16kV vital busses as designed.
1413	Emergency Response Organization (ERO) Pager message	Pagers set off to alert ERO to activate TSC and OSC for LOOP event
1414		Notice of Unusual Event is declared based on the loss of all AC power from offsite sources for more than 15 minutes with onsite power available. (Sent from the Control Room)
1421		Group call made to notify 4 of 5 state/local emergency management agencies. York County not available on selective signal call group.
1430	-----	Site Assembly initiated
1458		York County notified by commercial telephone line
1532	-----	Site Assembly completed, all personnel accounted for
1535	Message #2	Event update provided to 4 of 5 state/local emergency management agencies by selective signal call group. York County notified by commercial telephone line.
1550	-----	Technical Support Center (TSC) and Operations Support Center (OSC) activated
1615	-----	The NRC Operations Center was notified of the event by TSC staff 61 minutes late. The one hour notification was not made as required by the Control Room Offsite Agency Communicator.
1626	Message #3	Event update provided to State and local agencies (Sent from the TSC)
1717	Message #4	Event update provided to State and local agencies (Sent from the TSC)

1810	Message #5	Event update provided to State and local agencies (Sent from the TSC)

May 20, 2006 (continued)

TIME	COMMENT	DESCRIPTION
1819	-----	Emergency Operations Facility (EOF) activated at the request of the TSC Emergency Coordinator. The EOF provided support to the site by assuming the responsibility of conducting offsite agency communications and performing dose projections.
1858	Message #6	Event update provided to State and local agencies (Sent from the EOF)
1949	Message #7	Event update provided to State and local agencies (Sent from the EOF)
2041	Message #8	Event update provided to State and local agencies (Sent from the EOF). Offsite power restoration in progress. Message content "*Offsite power partially restored to Unit 2 at 2027*"
2054	Message #9	Event update provided to State and local agencies (Sent from the EOF). Message content "*Offsite power restoration in progress. Offsite power partially restored to both Unit 1 and Unit 2.*"
2148	Message #10	Event update provided to State and local agencies (Sent from the EOF). Message content "*Power restoration to plant systems in progress.*"
2246	Message #11	Event update provided to State and local agencies (Sent from the EOF). Message content "*Power and equipment restoration continues. Commencing cooldown to comply with facility Technical Specifications.*"
2339	Message #12	Event update provided to State and local agencies (Sent from the EOF). Message content "*Power and equipment restoration continues. Cooldown on both units in progress to comply with facility Technical Specifications.*"

May 21, 2006

TIME	COMMENT	DESCRIPTION
0033	Message #13	Event update provided to State and local agencies (Sent from the EOF). Message content "*Equipment and power restoration continues. Power has been restored to 3 of 4 essential busses. Cooldown continues on both units to comply with facility Technical Specifications.*"
0123	Message #14	Event update provided to State and local agencies (Sent from the EOF). Message content "*Cooldown no longer necessary and temperatures are being maintained steady. Power has now been restored to all 4 essential busses from offsite sources.*"
0145	Message #15	Event update provided to State and local agencies (Sent from the EOF). Message content "*Power has been restored to all essential busses. Plant conditions are stable. Unusual Event has been terminated.*"

INTEGRATED PLANT SEQUENCE OF EVENTS

Catawba Unit 1

TIME	EVENT DESCRIPTION
	May 20, 2006
14:01:45	An internal fault occurred in a current transformer associated with power circuit breaker (PCB) 18. This fault resulted in a loss of the 230 kV Yellow and Red busses and a 1A Zone lockout.
14:01:49	The first-out annunciator was "NI Hi Flux Rate – Power Range"; however, a review of reactor power traces do not show any valid increase or change in reactor power at this time (NOTE: The licensee is reviewing data to determine the cause of this signal). Both reactor trip breakers open and control rods insert. The main turbine trips on receipt of the reactor trip signal.
14:02:13	Diesel generators 1A and 1B start and re-energize the 1ETA and 1ETB 4.16kV emergency busses as designed.
14:02:30	Both main feedwater pumps trip on Lo-Lo suction pressure as a result of the loss of the hotwell and condensate booster pumps. The auxiliary feedwater pumps (two motor-driven and one turbine-driven) start automatically and provide inventory makeup to the steam generators.
14:07:34	Letdown isolation occurs when pressurizer level reaches 17%. Excess letdown could not be established due to the failure of the excess letdown control valve to open on demand. Normal letdown was subsequently re-established through the fixed orifice line due to the variable orifice control valve failing closed following the LOOP and not re-opening.
14:08:02	Main Steam Isolation signal is received when the 1C steam generator pressure reached 775 psig on 2/3 channels. Secondary pressure control transitions to the steam generator PORV's.
14:12	Intermediate Range nuclear instrumentation drops below 1E-10 amps (P6 setpoint).
14:14	Operations Shift Manager declared a Notice of Unusual Event (Emergency Action Level 4.5.U.1, "AC electrical power from all offsite sources has been lost for more than 15 minutes with onsite power available") due to the dual unit loss of offsite power. Emergency Response Organization page sent to activate the Technical Support Center (TSC) and Operations Support Center (OSC) (See Emergency Event Notification timeline for details on the licensee's response to the event).

14:22 Due to the loss of pressurizer spray (no forced circulation following the loss of the reactor coolant pumps), two of three pressurizer PORV's begin to cycle to control primary system pressure. (See section 4OA5.4 for details on the pressurizer PORV lifts). No pressurizer safety valves opened during the event.

14:55 Normal letdown is restored through the fixed orifice line.

20:34 Unit is stabilized on natural circulation using emergency, abnormal and normal operating procedures. Primary system parameters are being controlled through the use of auxiliary feedwater and steam generator PORV's.

20:40 Offsite power is restored to the 6.9kV non-vital busses. Work is in-progress to energize the 4.16kV vital busses from offsite power and secure the diesel generators.

21:55 Final pressurizer PORV actuation. Total number of actuations during event on PORV 1NC-34A was 57 cycles and on PORV 1NC-32B, five cycles.

23:03 4.16kV vital bus 1ETB is aligned to offsite power.

23:06 1B diesel generator output breaker is opened. Actions initiated to secure the 1B diesel generator and place it in stand-by.

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01:11 4.16kV vital bus 1ETA is aligned to offsite power. Due to the 1A Zone lockout, power is being supplied from the Unit 2 A SAT using procedural guidance to establish the required alignment.

01:14 1A diesel generator output breaker is opened. Actions initiated to secure the 1A diesel generator and place it in stand-by.

01:40 Notice of Unusual Event is terminated following restoration of offsite power to all unit busses.

15:17 The 1B reactor coolant pump is placed in service restoring forced circulation in the primary system and providing normal pressurizer sprays for pressure control if required. Primary system is stabilized at 475 F and 1850 psig in Mode 3.

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06:03 The 1B reactor coolant pump motor stator winding temperatures increase to 295°F requiring the pump to be secured. The 1A reactor coolant pump is started.

08:35 Stator winding temperatures on the 1A reactor coolant pump motor increase and approach the 300°F operating limit. The pump is secured and the decision made to cool down to Mode 5 using natural circulation in order to place residual heat removal in service. (NOTE: The elevated temperatures were determined to have been caused by biological debris being swept into the motor coolers when the source of cooling water swapped from the normal containment chilled water system to the backup nuclear service water system on the loss of offsite power).

08:49 Briefing conducted to initiate a natural circulation Cooldown to Mode 5.

16:07 Unit 1 enters Mode 4

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09:09 Unit 1 enters Mode 5

--------- The unit is stabilized at 170°F and 295 psig in Mode 5. The A train of residual heat removal is placed in-service for decay heat removal. The B train is placed in-service at 21:17. Repair and recovery actions are initiated.

CATAWBA UNIT 2

TIME	EVENT DESCRIPTION
	May 20, 2006
14:01:45	An internal fault occurred in a current transformer associated with power circuit breaker (PCB) 18. This fault resulted in a loss of the 230 kV Yellow and Red busses and a 2B Zone lockout.
14:01:46	The first-out annunciator is "Under Frequency Conditions on the Reactor Coolant Pump Busses" as sensed by the reactor coolant pump monitoring circuit. Both reactor trip breakers open and control rods insert. The main turbine trips on receipt of the reactor trip signal.
14:02	Diesel generators 2A and 2B start and re-energize the 2ETA and 2ETB 4.16kV emergency busses as designed.
14:02	Both main feedwater pumps trip on Lo-Lo suction pressure as a result of the loss of the hotwell and condensate booster pumps. The auxiliary feedwater pumps (two motor-driven and one turbine-driven) start automatically and provide inventory makeup to the steam generators.
14:08:05	Letdown isolation occurs when pressurizer level reaches 17%. Excess letdown is placed in service. Normal letdown was subsequently re-established.
14:08:21	Main Steam Isolation signal is received when the 2A steam generator pressure reached 775 psig on 2/3 channels. Secondary pressure control transitioned to the steam generator PORV's.
14:27	Due to the loss of pressurizer spray (no forced circulation following the loss of the reactor coolant pumps), one of three pressurizer PORV's begins to cycle to control primary system pressure. (See section 4OA5.4 for details on the pressurizer PORV lifts). No pressurizer safety valves opened during the event.
14:13	Intermediate Range nuclear instrumentation drops below 1E-10 amps (P6 setpoint).
14:14	Operations Shift Manager declares a Notice of Unusual Event (Emergency Action Level 4.5.U.1, "AC electrical power from all offsite sources has been lost for more than 15 minutes with onsite power available") due to the dual unit loss of offsite power. Emergency Response Organization page is sent to activate the Technical Support Center (TSC) and Operations Support Center (OSC). (See Emergency Event Notification timeline for details on the licensee's response to the event)
18:10	Final pressurizer PORV actuation. Total number of actuations during event on PORV 2NC-34A was 35 cycles.

---------- Unit is stabilized on natural circulation using emergency, abnormal and normal operating procedures. Primary system parameters are being controlled through the use of auxiliary feedwater and steam generator PORV's.

20:27 Offsite power is restored to the 6.9kV non-vital busses. Work is in-progress to re-energize the 4.16kV vital busses from offsite power and secure the diesel generators.

23:31 4.16kV vital bus 2ETA is aligned to offsite power.

23:36 2A diesel generator output breaker is opened. Actions initiated to secure the 2A diesel generator and place it in stand-by.

23:53 4.16kV vital bus 2ETB is aligned to offsite power. Due to the 2B Zone lockout, power is being supplied from the Unit 1 B SAT using procedural

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23:57 2B diesel generator output breaker is opened. Actions initiated to secure the 2B diesel generator and place it in stand-by.

01:40 Notice of Unusual Event terminated following restoration of offsite power to all unit busses.

11:06 The 2B reactor coolant pump was placed in service restoring forced circulation in the primary system and providing normal pressurizer sprays for pressure control if required. Exited Natural Circulation EP and transitioned to OP/2/A/6100/002; Controlling Procedure for Unit Shutdown

12:00 The unit was stabilized at 460 F and 1900 psig in Mode 3. Recovery actions are initiated.

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11:00 Vacuum is reestablished in the main condenser allowing secondary pressure control to be transferred from the steam generator PORV's to the steam dumps and conserve inventory required to feed the steam generators.